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July 29, 2005

BY OVERNIGHT DELIVERY AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's prefiled rebuttal testimony to the following filed direct testimony in the above-referenced proceeding:

Exhibit BSG/Rebuttal-1 – Mr. Effron
Exhibit BSG/Rebuttal-2 – Mr. Cavallo
Exhibit BSG/Rebuttal-3 – Mr. Newhard
Exhibit BSG/Rebuttal-4 – Mr. Pous
Exhibit BSG/Rebuttal-5 – Dr. Pereira
Exhibit BSG/Rebuttal-6 – Ms. Brockway

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French / JRB

Patricia M. French

cc: Per Ground Rules Memorandum issued June 13, 2005:

Paul E. Osborne, Assistant Director – Rates and Rev. Requirements Div. (1 copy)
A. John Sullivan, Rates and Rev. Requirements Div. (4 copies)
Andreas Thanos, Assistant Director, Gas Division (1 copy)
Alexander Cochis, Assistant Attorney General (4 copies)
Service List (1 electronic copy)

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S TESTIMONY IN REBUTTAL TO DAVID J. EFFRON

<u>Panel Witnesses</u>:
Stephen H. Bryant, President
John E. Skirtich, Consultant (Revenue Requirements)
Paul Moul, Consultant (Rate of Return, Cost of Capital)

IN SUPPORT OF
BAY STATE GAS COMPANY'S
REQUEST FOR INCREASE IN BASE REVENUE AND OTHER RATE MODIFICATIONS

EXH. BSG/REBUTTAL - 1

JULY 29, 2005

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES AND TITLES AND IDENTIFY WHETHER YOU FILED TESTIMONY PREVIOUSLY IN THIS PROCEEDING.

A. [By Mr. Bryant:] My name is Stephen H. Bryant, President, Bay State Gas Company ("Bay State" or the "Company"). I filed testimony that has been identified in the record as Exh. BSG-SHB-1.

A. [By Mr. Skirtich:] My name is John E. Skirtich, a consultant specializing in revenue requirements analysis for Bay State and other NiSource operating companies. I filed testimony that has been identified in the record as Exh. BSG-JES-1, as well as accompanying schedules and exhibits in support of Bay State's rate request.

A. [By Mr. Moul:] My name is Paul R. Moul, a consultant who provided return on equity and capital recommendations for Bay State. I filed testimony that has been identified in the record as Exh. BSG-PRM-1, as well as testimony filed today that is premarked Exh. BSG-Rebuttal-3.

Q. MR. BRYANT, WHAT IS THE SCOPE OF YOUR REBUTTAL TESTIMONY?

A. I have been asked to comment on Mr. Effron's statements relative to Bay State's Steel Infrastructure Replacement ("SIR") program, as well as his comments regarding Bay State's request for recovery of the undepreciated investment in its Metscan meter technology, and for recovery of the lease buy-out payment for Metscan.

Q. MR. SKIRTICH, WHAT IS THE SCOPE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. [By Mr. Skirtich:] The purpose of my rebuttal testimony is to reconcile the $7 plus million discrepancy that Mr. Effron shows in Schedule DJE-2 and direct him to the appropriate Company schedules for the amounts he did not include in his analysis. I will also rebut Mr. Effron's position on the amortization of deferred tax deficiencies.

Q. MR. MOUL, WHAT IS THE SCOPE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. [By Mr. Moul:] The purpose of my rebuttal testimony is to address Mr. Effron's comments about the impact of the Company's pension/PBOP expense reconciliation mechanism on Bay State's approved return on equity.

<u>II. STEEL INFRASTRUCTURE REPLACEMENT</u>

Q. **WHAT RECOMMENDATION DOES MR. EFFRON MAKE RELATIVE TO BAY STATE'S STEEL INFRASTRUCTURE REPLACEMENT BASE RATE RECOVERY MECHANISM?**

A. [By Mr. Bryant:] Mr. Effron states that the SIR program base rate adjustment mechanism is "unnecessary" because the PBR allows Bay State "an implicit recovery" of increases in net capital investment and if the annual depreciation expense is equal or greater than additions to plant in service, the balance of net plant will be steady. Therefore, the "implicit allowance" in the PBR "may" be adequate to compensate Bay State for its annual SIR additions. Therefore, Mr. Effron argues, the annual base rate adjustment mechanism (or "ABRAM") should be rejected. Mr. Effron also claims that Bay State has overstated its prior year replacement activities, asserts that Bay State should not earn carrying costs on its additional extraordinary plant investment during the year, and argues that Bay State has failed to reflect the expected reduction in depreciation expense that will result from its plant additions in any of its illustrative filed exhibits.

Q. **HOW DO YOU RESPOND TO THIS POSITION?**

A. [By Mr. Bryant:] The annual depreciation expense compensates Bay State for its current plant investment, not future investments that would be associated with the SIR program. Further, the rate recovery mechanism eliminates an amount of plant equivalent to the Company's historical level of steel infrastructure replacement, and thus only provides for rate recovery associated with the

Company's accelerated level of non-revenue producing steel infrastructure investment.

III. REVENUE ANNUALIZATION

Q. WHAT IS THE CAUSE OF THE REVENUE DISCREPANCY THAT MR. EFFRON DISCUSSES IN HIS TESTIMONY?

A. [By Mr. Skirtich:] The major cause of the revenue discrepancy is the result of Mr. Effron not including the non-recurring revenue adjustments made by Mr. Ferro, as shown on Schedule JAF-1-1, Sheet 1, Column 3. The total of the non-recurring revenue is a reduction to revenue of $8,140,593. This amount is offset by approximately $654,000 of other corrections and adjustments to arrive at the Mr. Effron's $7.486 million discrepancy.

Q. DID YOU PREPARE A SCHEDULE RECONCILING THE DISCREPANCY?

A. [By Mr. Skirtich:] Yes, I did. Attached is Schedule BSG-Rebuttal-1-1 that consists of three pages. Page One reconciles Mr. Effron's discrepancy, and Pages Two and Three illustrate the impact on operating margin of the revenue and O&M expense entries the Company made. The reconciling items shown on Page One originate from Pages Two and Three.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED PAGES TWO AND THREE?

A. [By Mr. Skirtich:] Page Two, Column 1 starts with per books operating margin with a breakout of revenue from Schedule JES-4, and a detail of specific O&M expense items. The total amounts for revenue, gas costs, and O&M expense tie to Exhibit BSG/JES-1, Schedule JES-1, Column 1. Operating margin per books of $87,586,339 is shown in Column 1, Line 28, which agrees with Mr. Effron's operating margin per books that he used in Schedule DJE-2. All the adjustments to operating revenue and O&M expenses made by the Company are identified. They are shown in Columns 2-14 of Page Two, and Columns 2-7 of Page Three. Combining the operating margin per books with the adjustments made by the Company arrives at the adjusted book amounts as shown in Column 8 of Page Three, which agrees with Schedule JES-1, Column 3.

Q. PLEASE EXPLAIN THE NON-RECURRING ITEMS SHOWN ON PAGE 1, LINE 2.

A. [By Mr. Skirtich:] The $8.140 million consists of 4 items. The impact, when eliminated, on operating margin is shown on Page 2, Columns 4 through 7. The sum of these amounts, $8,140,593, is shown in Schedule JAF-1-1, Column 3.

For the first item shown in Column 3 of Schedule JAF-1-1, the Company is eliminating revenue related to Lost Base Revenue ("LBR") recoverable consistent with the Company's Local Distribution Adjustment Clause ("LDAC") and the Departments policy on LBR. The Company is eliminating the LBR so base rates can be adjusted to reflect the lower revenue due to its Demand Side Management programs.

The second item totaling $2,306,562 relates to LBR recoverable through the Company's exogenous factor. The Department's current policy for recovery of LBR provides for recovery using a rolling average of the Company's last four rate cases. This policy was adopted during Bay State's rate freeze preventing the Company from securing rate relief through a general rate case. Bay State filed for recovery of the LBR reflecting the previous policy through the exogenous clause of its tariff. On May 14, 2004, Bay State filed for recovery of $2,169,462 of LBR plus related interest (D.T.E 04-57) and in October 2004 recorded the LBR to income. This one time exogenous revenue needs to be eliminated to properly establish base rates.

The third item, carrying cost primarily related to gas cost, totals $4,359,196 and reflects the recognition of carrying costs recovered via the Cost of Gas Adjustment Clause ("CGA"). Since these revenues are collected via the CGA, the revenue must be eliminated. Furthermore, rate base includes no gas cost working capital to match the carrying costs.

Finally, the Non-recurring items reflect an adjustment of $66,908 related to production and storage revenue. The Company is authorized to recover $9,129,632 of revenue annually as approved at D.P.U 95-104 related to production and storage. For accounting purpose, this amount is recorded monthly based on a revenue curve and the twelve months ending October. As a result, any calendar period may have a slight discrepancy in the amount of revenue recognized as compared to the approved amount. As a result, the Company made an adjustment reducing revenue.

Q. WHAT IS THE TOTAL OF THE NON-RECURRING ITEMS?

A. [By Mr. Skirtich:] Again, as shown in Column 3 of JAF-1-1, the total of the Non-recurring items is $8,140,593, and the total of Columns 4 thru 7 on Schedule JES-1, Page 2 of 3, which Mr. Effron did not consider.

Q. WHAT MAKES UP THE DIFFERENCE BETWEEN THE $8.140 MILLION AND MR. EFFRON'S $7.486 MILLION DISCREPANCY?

A. [By Mr. Skirtich:] The difference is made up of primarily three items totaling $644,603. They are as follows: GAF recoveries of $186,069 not offset in Column 2 of JAF-1-1; a difference of $84,779 of actual DAF recoveries versus the DAF recoverable dollars reflected on the books; and $373,735 of unbilled DAF revenue not separately displayed in Schedule JAF-1-1, but rather included in Column 6 along with all the other adjustments and variances. The operating margin impacts are shown in Columns 2 and 8 of Page 2 and Column 3 of Page 3, respectively. For all three of these items, less revenue should have been reflected in the revenue section of their respective column, which would then eliminate the operating margin impact. The reduction in revenue would be offset with an increase in revenue under Column 13, Miscellaneous Adjustment. The total Operating

Margin amount for the Miscellaneous Adjustments would have increased to $1,120,346 ($475,743 + $644,603).

Q. WHY WOULDN'T OPERATING MARGIN CHANGE AS A RESULT OF PROPERLY REFLECTING THESE ITEMS?

A. [By Mr. Skirtich:] The development of Annualized Delivery Service Revenue as shown in Column 7 of Schedule JAF-1-1 is a separate and distinct calculation. It is the result of applying rates in effect during the test year to calendarized, normalized physical flow volumes on a customer by customer basis and aggregated by rate schedule (please refer to WP JAF-1-2-1 through WP JAF 1-2-12 for the monthly calculation.). Columns 2 through 6 of Schedule JAF 1-1 represents a check of Column 7 by identifying the major differences between per book revenue and the calculated Annualized Delivery Service Revenue calculated separately.

Q. PLEASE EXPLAIN THEN WHAT THE REVISED OR CORRECTED $1,120,346 OF OPERATING MARGIN UNDER MISCELLANEOUS ADJUSTMENTS REPRESENTS?

A. [By Mr. Skirtich:] The $1,120,346 is the total amount that should have been shown under Schedule JAF 1-1, Column 6 (Adjustment to Reflect Annualization). This amount primarily represents three categories of adjustments. 1) Per books unbilled volumetric revenues during the test year were calculated by applying average volumetric margin rates to estimated unbilled volumes by class, where for the filing in WP JAF 1-2-1 through WP JAF 1-2-12 calendarized normalized volumes were split between the head block and tail block on a customer by customer basis and applied to the appropriate block rate creating a slightly more accurate calculation of unbilled revenue and contributing to the Schedule JAF 1-1 Column 6 amount. 2) Policy revenue adjustments compensating customers for Company actions or inactions included in book revenue were eliminated in Column 6 by default since none were reflected in the determination of Annualized Delivery Service Revenue. 3) Finally, customer billing adjustments also fall into Column 6. When a customer adjustment is made, the full impact is recognized in the month the adjustment is made for accounting purposes. The normalization process moves the adjustment to the correct period resulting in a revenue impact included in Column 6. Between these three general categories of adjustments there are literally thousands of minor adjustments that make up the total amount shown in Column 6.

Q. **DID YOU REVIEW MR. EFFRON'S ALTERNATIVE ANALYSIS AS SHOWN ON SCHEDULE DJE-2, PAGE 2?**

A. [By Mr. Skirtich:] Very briefly. I am familiar with the return on equity calculation as reflected in the Company's Annual Return to the DTE. In reviewing the alternative analysis, I saw that Mr. Effron was taking the calculation from the Annual Return and making adjustments reflecting differences between the Annual Return numbers and the amounts reflecting in the Company's filing. I noticed that he again omitted the Non-recurring revenue adjustments, therefore I didn't see any need to continue any further review. The omission of the Non-recurring items explains the discrepancy on both analyses.

III. METSCAN AMORTIZATION

Q. DO YOU AGREE WITH MR. EFFRON'S POSITION ON THE AMORTIZATION OF METSCAN COSTS?

A. [By Mr. Bryant:] No, I do not. The decision to install the devices was reasonable and prudent based on what the Company knew or should have known at the time, and the Metscan units provided customer benefits in terms of more accurate and timely meter readings and bills. These devices also improved operating efficiencies and lead to cost savings while they were in service. The Company removed the amounts still in rate base at the end of the year and the lease payment from O&M expense. Although the purchase of the Metscan devices was extraordinary and non-recurring, and the majority of these devices are no longer being used and are retired, this significant, undepreciated plant balance and the pay off of the lease payment should be treated as a non-recurring cost and amortized over a reasonable period. This would allow for a return of and not a return on the unamortized balance of the remaining regulatory asset, and is consistent with Department precedent as noted in the Company's response to information request DTE-1-24.

IV. AMORTIZATION OF DEFERRED TAXES DEFICIENCY

Q. DO YOU AGREE WITH MR. EFFRON'S ADJUSTMENT TO THE COMPANY'S PROPOSED INCREASE IN AMORTIZATION OF ITS DEFERRED TAX DEFICIENCY?

A. [By Mr. Bryant:] I am not a tax expert. However, to my understanding the Company received approval to recover its deferred tax deficiency in its 1992 general rate case at DPU 92-111 using the "Reverse South Georgia Methodology." Unlike the "Average Rate Assumption Methodology," the Reverse South Georgia Methodology is a straight-line amortization, and can only change by approval of the regulatory body overseeing the utility. The Company is updating its deficiency for calendar year 1992 activity since the 1992 rate case was based on 1991 test year. I do not believe the Company had the authority to start amortizing the amortization of the 1992 deficiency starting in 1992 as proposed by Mr. Effron without Department approval.

V. MR. EFFRON'S PROPOSED ADJUSTMENT TO ROE

Q. MR. MOUL, WHAT DID MR. EFFRON SAY ABOUT HOW THE COMPANY'S COST OF EQUITY WOULD BE AFFECTED BY THE APPROVAL OF THE PENSION/PBOP EXPENSE RECONCILIATION MECHANISM?

A. [By Mr. Moul:] Mr. Effron stated on page 11 of his prefiled testimony that the approval of the Pension/PBOP expense reconciliation mechanism ("PPM") should be accompanied by a reduction in the Company's authorized return on common equity.

Q. DO YOU AGREE WITH MR. EFFRON'S ASSESSMENT?

A. [By Mr. Moul:] No. As a preliminary matter, it should be noted that the pension issue is not a financial issue, but rather a business risk issue. As described in my Exhibit BSG/ PRM-1, the cost of equity established for a public utility should permit it an opportunity to earn a rate of return on common equity commensurate with the risk to which invested capital is exposed. In that regard, my recommendation for the allowed return on equity is based on analyses of data collected from a group of companies comparable to the Company. I do not believe that the calculation of the return on equity based on the Gas Group can be adjusted to isolate or differentiate the risk associated with the recovery of pension costs from any other cost-of-service item.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT?

A. [By Mr. Moul:] Historically, investors have perceived that regulators would permit the recovery of prudently incurred costs associated with the fulfillment of a utility's service obligations, including the obligation to provide pension benefits to employees. That is to say, in the long run, investors have not regarded pension costs any differently from other cost-of-service items that are fully recoverable from customers. Moreover, as indicated in response to Information Request AG-20-3, some of the members of the Gas Group have a variety of mechanisms in place to deal with pension cost-recovery.

Q. **WHAT IS YOUR OPINION REGARDING THE EFFECT OF THE DEPARTMENT'S APPROVAL OF THE COMPANY'S PROPOSAL?**

A. [By Mr. Moul:] Market setbacks during the last "bear" market for pension trust funds, coupled with stringently applied accounting rules, have created the potential for the booking of significant pension expenses. Further, the volatility of the stock market makes it increasingly difficult to select a representative amount of pension expense to include in the cost of service. The two-fold impact of recent stock market volatility and restrictive accounting requirements have prompted the Company to propose a reconciling mechanism in this case. This mechanism is especially important for the Company in the context of its PBR proposal, which is not designed to accommodate the interrelated issues of market volatility and restrictive pension accounting requirements. It is my opinion that the approval of the mechanism proposed by Bay State will maintain the status quo for the Company and its customers so as to avoid penalizing the Company as a result of including in rates a level of pension expense that is too low, or penalizing customers if the amount included in rates were set too high.

Q. WHAT IS YOUR RECOMMENDATION REGARDING AN ADJUSTMENT TO THE EQUITY RETURN RELATING TO THE PROPOSED PENSION RECONCILIATION MECHANISM?

A. [By Mr. Moul:] If the Department approves the pension mechanism, there is no change warranted in my cost of equity recommendation. The level of risk generally perceived by financial markets indicates that there is no quantifiable basis to adjust the risk premium that may be attributed to this issue. If no risk premium is identifiable, then there is no basis to remove any premium from the cost of equity. Therefore, no adjustment to the 11.50 percent return on common equity that I have recommended would be necessary or appropriate.

If the Department were to reduce the allowed cost of equity in this case to account for the pension reconciliation mechanism, then the Company's risk could increase as a reaction to a lowered rate of return that removes a risk premium for pensions where none exists.

<u>VI. CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. [By Messrs. Bryant, Skirtich and Moul:] Yes, subject to reserving my right to provide additional necessary information following receipt and review of Bay State's discovery of Mr. Effron.

Bay State Gas Company
Reconciliation of Effron's Discrepancy

Ln. No.	Item	Amount ($000)
1	Discrepancy per Schedule DJE-2	7,486
2	Non-recurring items per Schedule JAF-1-1, Sheet 1, Column 3	(8,140)
3	Inadvertent GAF recoveries not offset	186
4	Book Versus Actual Collections on DAF	85
5	Unbilled DAF incorrectly eliminated	373
6	Bad Debt	12
7	Discrepancy (Rounding)	2

Bay State Gas Company
Reconciliation to Effron's Schedule

Ln. No.	Item	Per Books JES-1	JAF-1-1 Column 2 GAF Collections	JAF-1-1 Column 2 Off-Systems Sales	JAF-1-1, Column 3 LNR	JAF-1-1, Column 3 LBR	JAF-1-1, Column 3 Working Capital	JAF-1-1, Column 3 Production & Storage	JAF-1-1 Column 4 DAF Collections	JAF-1-1 Col.5 Weather Adjustment	Sch. JAF-1-1, Column 6 Unbilled	Sch. JAF-1-1, Column 6 Special Rate AG-9-2	Sch. JAF-1-1, Column 6 Leap Year	Sch. JAF-1-1, Column 6 Misc. Adj	Sch. JAF-1-1, Column 6 Interruptible Sales	Total Sch. JAF-1-1, Sh.1
		(1) ($)	(2) ($)	(3) ($)	(4) ($)	(5) ($)	(6) ($)	(7) ($)	(8) ($)	(9) ($)	(10) ($)	(11) ($)	(12) ($)	(13) ($)	(14) ($)	(15) ($)
1	Residential Sales Revenue	334,824,296	(228,869,211)	-					(3,421,744)	(1,714,352)	(7,446,802)		(45,669)	583,749		93,910,267
2	Comm/Industrial Sales Revenue	127,857,611	(94,823,251)	-					(1,342,343)	(592,832)	(4,819,269)	(404,852)	(40,978)	502,011		26,336,097
3	Interruptible Sales Revenue	2,904,376	-	-	-	-	-	-	-	-	-	-	-	-	(2,904,376)	-
4	TOTAL TARIFF REVENUES	465,586,283	(323,692,462)	-	-	-	-	-	(4,764,087)	(2,307,184)	(12,266,071)	(404,852)	(86,647)	1,085,760	(2,904,376)	120,246,364
5	Residential Transportation of Gas	21,028							(1,117)	(504)				4,636		24,043
6	Comm/Industrial Transportation of Gas	23,754,251							(1,776,995)	(247,894)				(652,622)		21,076,740
7	Off System Sales	3,874,467		(3,874,467)												-
8	Gas Property Revenue	1,513,333														1,513,333
9	Rental Revenue	6,824,456														6,824,456
10	Guardian Care/Inspections	7,690,936														7,690,936
11	Lost Net Revenue	329,951			(1,224,169)	(2,169,462)			3,063,681							1
12	Late Payment Charges	685,241														685,241
12	Return Check Charge	27,736														27,736
13	Carrying Costs-Pre tax of Rate of Return	(988,819)	5,668,863		(183,746)	(137,100)	(4,359,196)									2
14	Prod & Storage Revenues	1,044,497	8,152,043					(66,908)								9,129,632
15	Customer R&C Shut-off Turn-off	93,975	-	-	-	-	-	-	-	-	-	-	-	-	-	93,975
16	TOTAL OTHER OPER. REVENUES	44,871,052	13,820,906	(3,874,467)	(1,407,915)	(2,306,562)	(4,359,196)	(66,908)	1,285,569	(248,398)		-	-	(647,986)		47,066,095
17	Elimination of Indirect GAF and DAF	-			-	-	-	-		-		-				-
18	Add back Bad Debt Exp. Included in Indir	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Revenue	510,457,335	(309,871,556)	(3,874,467)	(1,407,915)	(2,306,562)	(4,359,196)	(66,908)	(3,478,518)	(2,555,582)	(12,266,071)	(404,852)	(86,647)	437,774	(2,904,376)	167,312,459
20	Gas Costs	323,863,512	(304,767,510)	(3,874,467)	-	-	-	-	-	-	(12,266,071)	-	-	(37,969)	(2,917,495)	-
21	Operating Expenses	89,780,317	-	-												89,780,317
22	Bad Debt	5,290,135	(5,290,135)													-
23	ERC	1,210,869							(1,210,869)							-
24	CHOice	(65,832)							65,832							-
25	Unbilled LDAF	373,735														373,735
26	DSM	2,418,260	-	-	-	-	-	-	(2,418,260)	-	-	-	-	-	-	-
27	Total	99,007,484	(5,290,135)	-	-	-	-	-	(3,563,297)	-	-	-	-	-	-	90,154,052
28	Operating Margin	87,586,339	186,089	-	(1,407,915)	(2,306,562)	(4,359,196)	(66,908)	84,779	(2,555,582)	-	(404,852)	(86,647)	475,743	13,119	77,158,407
29	Corrections	-	(186,089)	-	-	-	-	-	(84,779)	-	-	-	-	644,603	-	373,735
30	Operating Margin - as corrected	87,586,339	-	-	(1,407,915)	(2,306,562)	(4,359,196)	(66,908)	-	(2,555,582)	-	(404,852)	(86,647)	1,120,346	13,119	77,532,142

Bay State Gas Company
Reconciliation to Effron's Schedule

Ln. No.	Item	Total From Pg 1	O&M Adj. Excl Bad Debt & LDAC JES-6	Unbilled DAF JES-6, Pg. 1	Bad Debt	Direct GAF At Cur. Rates JAF-1-1, Sh 2,	Indirect GAF At Cur. Rates AF-1-1, Sh 2,	Annualized AF At Curr., AF-1-1, Sh 2,	Total Sch. JES-1
		(1) ($)	(2) ($)	(3) ($)	(4) ($)	(5) ($)	(6) ($)	(7) ($)	(8) ($)
1	Residential Sales Revenue	93,910,267				216,689,229	13,573,678	3,537,586	327,710,760
2	Comm/Industrial Sales Revenue	26,336,097				90,789,422	5,555,933	1,524,021	124,205,473
3	Interruptible Sales Revenue	-	-	-	-	-	-	-	-
4	TOTAL TARIFF REVENUES	120,246,364	-	-	-	307,478,651	19,129,611	5,061,607	451,916,233
5	Residential Transportation of Gas	24,043						1,152	25,195
6	Comm/Industrial Transportation of Gas	21,076,740						1,900,103	22,976,843
7	Off System Sales	-							-
8	Gas Property Revenue	1,513,333							1,513,333
9	Rental Revenue	6,824,456							6,824,456
10	Guardian Care/Inspections	7,690,936							7,690,936
11	Lost Net Revenue	1							1
12	Late Payment Charges	685,241							685,241
12	Return Check Charge	27,736							27,736
13	Carrying Costs-Pre tax of Rate of Return	2							2
14	Prod & Storage Revenues	9,129,632							9,129,632
15	Customer R&C Shut-off Turn-off	93,975	-	-	-	-	-	-	93,975
16	TOTAL OTHER OPER. REVENUES	47,066,095	-	-	-	-	-	1,901,255	48,967,350
17	Elimination of Indirect GAF and DAF	-	-				(19,129,611)	(6,962,862)	(26,092,473)
18	Add back Bad Debt Exp. Included in Indir	-	-	-	7,118,165	-	-	-	7,118,165
19	Total Revenue	167,312,459	-	-	7,118,165	307,478,651	-	-	481,909,275
20	Gas Costs	-	-	-	-	307,478,651	-	-	307,478,651
21	Operating Expenses	89,780,317	2,159,079						91,939,396
22	Bad Debt	-			7,106,032				7,106,032
23	ERC	-							-
24	CHOice	-							-
25	Unbilled LDAF	373,735		(373,735)					-
26	DSM	-	-	-	-	-	-	-	-
27	Total	90,154,052	2,159,079	(373,735)	7,106,032	-	-		99,045,428
28	Operating Margin	77,158,407	(2,159,079)	373,735	12,133	-	-	-	75,385,196
29	Corrections	373,735	-	(373,735)	-	-	-	-	-
30	Operating Margin - as corrected	77,532,142	(2,159,079)	-	12,133	-	-	-	75,385,196

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THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S PREFILED REBUTTAL TO THE FILED DIRECT TESTIMONY OF JON CAVALLO

Panel Witnesses:

Stephen H. Bryant, President
Danny G. Cote, General Manager

IN SUPPORT OF BAY STATE GAS COMPANY'S REQUEST FOR INCREASE IN BASE REVENUE AND OTHER RATE MODIFICATIONS

EXH. BSG/Rebuttal - 2

July 29, 2005

Q. PLEASE STATE YOUR NAMES AND TITLES AND IDENTIFY WHETHER YOU FILED TESTIMONY PREVIOUSLY IN THIS PROCEEDING.

A. [By Mr. Bryant:] My name is Stephen H. Bryant, President, Bay State Gas Company ("Bay State" or the "Company"). I filed testimony that has been identified in the record as Exh. BSG/SHB-1.

A. [By Mr. Cote:] My name is Danny G. Cote, General Manager, Bay State Gas Company. I filed testimony that has been identified in the record as Exh. BSG/DGC-1.

Q. HAVE EACH OF YOU REVIEWED THE DIRECT TESTIMONY OF JON CAVALLO IN THIS PROCEEDING?

A. Yes, we have.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. CAVALLO'S ASSERTIONS IN HIS PREPARED DIRECT TESTIMONY?

A. [By Mr. Cote:] Yes. To begin our rebuttal, we have a number of comments related to Mr. Cavallo's qualifications to give an opinion on the Bay State's steel infrastructure replacement ("SIR") program. Mr. Cavallo's experience does not appear to include corrosion leak investigation or remediation on bare or unprotected steel distribution systems, and/or the design of corrosion control systems for bare or unprotected coated underground natural gas utility distribution piping in the Northeast or in the United States.

Further, there is nothing in the record that indicates that Mr. Cavallo is qualified in compliance with Part 192 sub-section N of the federal pipeline safety regulations to perform field-testing, installation, remediation, or maintenance on coatings or cathodic protection systems in natural gas or oil service.

A. [By Mr. Bryant:] Because the issues of public safety, system integrity and service reliability are raised by Bay State's SIR program, it is important for the Department to evaluate Mr. Cavallo's critique of the SIR program and Bay State's infrastructure management by comparing Mr. Cavallo's relevant experience with the number of years of practical experience of Mr. Cote and Bay State's other distribution management and corrosion staff in operating a gas distribution system in Massachusetts.

A. [By Mr. Cote:] It is important to note that Bay State has National Association of Corrosion Engineer ("NACE") certified corrosion specialists available to it both on staff and through the consulting group that it uses routinely to evaluate its cathodic protection systems. While Mr. Cavallo references his membership in NACE (now NACE International and formerly the National Association of

Corrosion Engineers), he does not reference any NACE certification that he possesses. NACE is a highly respected professional organization that focuses on corrosion issues and training. While NACE membership is open to anyone, the various NACE certifications require substantial testing and practical experience. Bay State has a number of employees that have received certifications and training through NACE.

Q. HOW DO YOU EVALUATE MR. CAVALLO'S WORK ON THE AMERICAN SOCIETY OF TESTING AND MATERIALS ("ASTM") COMMITTEE D-33?

A. [By Mr. Cote:] From the ASTM website, the ASTM Committee D-33's scope is the development of standard specifications, test methods, practices, definitions, and classifications for organic and inorganic protective coating and lining work for power generation facilities. This does not appear to be particularly relevant to Mr. Cavallo's opinions in this proceeding.

Q. MR. CAVALLO ALLEGES THAT BAY STATE'S SIR PROGRAM IS "... IS NOT BASED ON SOUND ENGINEERING PRACTICES" AND THAT BAY STATE HAS MADE "NO EFFORT ... TO DETERMINE THE ROOT CAUSE(S) OF THE INCREASING LEAK RATE ...." CAVALLO DIRECT TESTIMONY, JULY 15, 2005, AT 7. PLEASE COMMENT.

A. [By Mr. Cote:] This is not true based on the fact that Bay State's management and corrosion staff review each corrosion leak and related work order to investigate patterns of corrosion activity. All main and service repairs and replacement priorities are based on this effort. The record of this proceeding is replete with information relative to the manner by which Bay State evaluates its system integrity, including its corrosion leak detection, repair and replacement procedures and practices.

Bay State's dynamic knowledge of its system, including the location and pattern of leak repairs and system replacements as tracked on its various distribution system maps, its frequent review of Work Order Management System ("WOMS") and Department of Transportation ("DOT") data, and the natural gas industry's acknowledgement that unprotected steel main and services will fail, has resulted in the determination that all three divisions, particularly Brockton, have a systemic bare and unprotected coated steel main and service leak problem. See the Company's June 29, June 27 and June 6 responses to information request AG-2-1 for a sampling of the various sources of leak and corrosion data available for its analysis. This dynamic and detailed information on leaks in the Company's system, rather than a static "root cause analysis," has been the basis for the determination that appropriate sections of mains and services will be replaced as determined by the worst leak records in an orderly, cost effective, geographic fashion over the next 10-15 years.

While a single root cause study has not been completed by Bay State in determining it needed to implement a SIR program, Bay State had effectively performed a continual and ongoing root cause analysis of its distribution system to determine the corrective action needed to be taken on certain segments of distribution pipeline. The value of Bay State's management and corrosion team's ongoing analysis and expertise in this area, in my opinion, far exceeds that of a one-time, special root cause analysis performed by an uninvolved, paid third party consultant.

The Company has undertaken continual efforts to determine the cause of its increasing leak rates in its underground infrastructure. See response to information request AG-23-4. Over the last 20 years, approximately 40 percent of the leaks repaired or eliminated were due to corrosion. In 2004, roughly 88 percent of the corrosion leaks repaired or eliminated occurred on bare and/or unprotected coated steel pipe and related components. Over the last 10 years, Bay State has geographically and chronologically tracked its distribution system leak repairs due to corrosion and identified areas prone to corrosive attack. These areas are tracked in Bay State's WOMS and shown on WOMS report wwrpt050.p. See response to information request AG-2-1 at attachment A. The material type most prone to corrosive attack is steel pipe. Steel pipe and related components without any coating or with poor coating are most prone to corrosive attack. The chemical composition of the pipe (i.e. ladle percent of carbon, manganese, phosphorus and sulfur) may also contribute to the pipe and components being more or less susceptible to corrosion. However, the ladle content and mill specification record for each length of steel pipe segment installed by Bay State's predecessor companies is no longer available.

Q. MR. COTE, WHY DOES BAY STATE NEED TO REPLACE ITS UNPROTECTED STEEL INFRASTRUCTURE?

A. Bay State determined the need for replacement of its unprotected steel infrastructure because it has a higher leak rate than other segments of its system due primarily to corrosion. From an operational standpoint, it is irrelevant whether the corrosion was caused or exacerbated by any one or more of the following: poor soil condition, backfill materials, electrical shorts, ineffective coating, bacteria, age, or some other reason. There is no question that all of the Company's unprotected steel infrastructure needs to be replaced, and the SIR program is the most orderly, cost effective way to do this.

Q. ASSUMING THAT MOIST SOIL SURROUNDING THE PIPE WAS DETERMINED THROUGH A ROOT CAUSE ANALYSIS TO BE A PRIMARY REASON FOR THE CORROSION, COULD THE COMPANY HAVE CORRECTED THAT CONDITION ON ITS REMAINING UNPROTECTED STEEL INFRASTRUCTURE?

A. [By Mr. Cote:] No. The only way to correct unfavorable soil conditions is to test the soil in proximity to each and every unprotected steel main, catalog those results, then excavate the unprotected mains where the soil is unfavorable, remove the fill and retrench the pipe. At that point, it is obvious given the age of these facilities, once the Company has gone to the trouble of excavating the pipe, it should replace it. Then we are right back to the point of how to design and implement the most cost-effective and practicable replacement program. Bay State believes the most effective way to do that is through geographic area replacement, rather than by a piecemeal approach. The evidence in this proceeding demonstrates that leaks are occurring throughout Bay State's three divisions, with the highest rate of leakage occurring in the Brockton division. Therefore, no pattern of leaks has erupted that would indicate a substantial section of the Brockton distribution system is subject to a different trench environment.

Q. DOES BAY STATE MANAGEMENT AND CORROSION STAFF CONTINUALLY EVALUATE CORROSION IN THE SYSTEM USING THE LATEST TECHNIQUES IN THE INDUSTRY?

A. [By Mr. Cote:] Yes. As noted above, Bay State undertakes an ongoing effort to identify areas and materials in the system that are more prone to corrosion. For example, these efforts include field investigations by corrosion and distribution staff, review of data from leak repair work orders, plotting of work order corrosion leak data onto corrosion leak maps, and the periodic review of corrosion leak maps. Periodic review of WOMS and DOT data to identify patterns and areas needing additional attention is also undertaken. Furthermore, this type of effort by Bay State is what will determine, on an annual basis, the SIR prioritization of work. Moreover, Bay State exceeds state and federal standards with regard to the frequency of its leak surveying. Bay State's management knows its system through its day-in-day-out operation of the distribution system and its consistent, diligent oversight and review of all available information that comes to light daily through its field crews and leak surveys.

Q. MR. CAVALLO ALSO ALLEGES THAT WITHOUT A "ROOT CAUSE ANALYSIS," BAY STATE MAY "UNWITTINGLY REPLICATE" THE CONDITIONS THAT CAUSED THE ORIGINAL CORROSION LEAKS. HOW DO YOU RESPOND TO THIS?

A. [By Mr. Cote:] This simply is not true. Most of the replacement pipe in the SIR program will be new polyethylene pipe, which cannot corrode. For that portion of system that we choose to replace with cathodically protected coated steel, Bay State cannot "'unwittingly replicate' conditions that cause the original corrosion leaks". Bay State continually tests its cathodic protection system to ensure that the currents run at the level mandated by federal code. Therefore, while corrosion may occur on modern, cathodically protected coated steel pipe, it is extremely rare and the conditions that lead to the existing leakage problem on Bay State's unprotected steel infrastructure will not be repeated.

Bay State's current operating practices and procedures related to the replacement of mains and services also demonstrate why the conditions that cause the original corrosion leaks will not be "unwittingly replicated". Bay State procedures reflect the current industry standards that are designed to ensure that any new coated and protected steel mains and services that are installed, whether to replace old facilities or expand the system, are protected to prevent corrosion. Furthermore, certified corrosion technicians survey the new and existing coated and protected steel mains and services and they will identify any areas requiring corrective action, which will then be undertaken.

Q. DOES MR. CAVALLO'S TESTIMONY HELP EXPLAIN THE NEED FOR A SIR PROGRAM AT BAY STATE?

A. [By Mr. Cote:] Actually yes. In Mr. Cavallo's testimony on page 10, he answers the question "Could you explain the relationship between coatings on buried steel pipe and corrosion mitigation?" His response explains what physically can happen to coated steel pipe in the field. He also explains what happens to coated steel pipe without cathodic protection if the coating is damaged. I agree with his explanation of one of the causes of corrosion leaks, which is rocks in contact with the main, but since this was created by historic construction practices, there is no action other than replacement that the Company can take. In addition, as Mr. Cavallo explains in his testimony, Bay State also has bare steel (and coated steel with ineffective coating), which is corroding uniformly.

Q. MR. CAVALLO INDICATES THAT IN THE RUDDEN REPORT, RUDDEN OR BAY STATE CLAIMS THAT BAY STATE LEAK DATA TRENDS ARE "POSTULATED" TO BE ASYMPTOTIC. IS THIS TRUE?

A. [By Mr. Cote:] No. The Rudden report provided a graphical illustration of what the leak rates of an unprotected pipe in the ground may look like assuming no action was taken to protect or repair it over time. This illustration was not depicting Bay State leak data.

Q. ON PAGE 14 OF HIS TESTIMONY MR. CAVALLO ASSERTS THAT THE LEAKS DO NOT APPEAR TO BE INCREASING, LOOKING AT FIVE YEARS OF DATA POINTS, 2000 THROUGH 2004. PLEASE RESPOND.

A. [By Mr. Cote:] This period is too short a time frame to form a definitive conclusion. In addition, Mr. Cavallo selected a specific time frame to suit his needs, which is not reasonable. If he were to add two more years (1998-99) the trend would be clearly be increasing. It is much more reasonable to evaluate the trend in leaks and leaks per mile over many years, as Bay State has done in its 20 year analysis, to provide a clearer indication of what is occurring on the distribution system. Further, Mr. Cavallo has failed to recognize in his testimony the important relationship between the recent downward trend in main leaks repaired during the same time the Company retired approximately 20 percent of its unprotected coated steel and approximately 12 percent of its bare unprotected steel main.

Q. ON PAGE 15 OF HIS TESTIMONY, MR. CAVALLO ALSO CHARACTERIZES THE RUDDEN REPORT AS CLAIMING BAY STATE'S LEAK RATES ARE DRAMATIC AND ASYMPTOTIC. IS THIS TRUE?

A. [By Mr. Cote:] No. Rudden's report provides a clear and compelling presentation of publicly available data that proves three primary points:

1. The leak rate (leaks/mile) on the Brockton Division bare steel and unprotected coated steel pipe remaining on the system has continued to increase. This is true even in light of Bay State's continued replacement and reduction of these pipe materials remaining on the system. This is illustrated on Chart #8 of the Rudden report. See Bay State's response to information request AG-2-16.
2. The Brockton Division leak rate for bare steel and unprotected coated steel pipe is in the highest quartile for data from comparable companies on a national and regional basis. This is illustrated on Charts #9 and #10 of the Rudden report. See Bay State's response to information request AG-2-16.
3. To date, Bay State has managed their leak rates well, relative to their peers on a national and regional basis, by providing timely repair of leaks. This is illustrated on Charts #3, #4, #5 and #6 of the Rudden report. See Bay State's response to information request AG-2-16.

Q. ON PAGE 15 OF HIS TESTIMONY MR. CAVALLO ALSO CLAIMS THAT BY FILLING AN EXCAVATED TRENCH FOR REPAIRED UNPROTECTED STEEL WITH THE SAME FILL THAT WAS

REMOVED, AND NOT CLEAN FILL, BAY STATE HAS CONTRIBUTED TO THE DAMAGE ON ITS PIPES AND VIOLATED ITS OWN BACKFILLING O&M STANDARDS. IS THIS TRUE?

A. [By Mr. Cote:] No. Mr. Cavallo makes several statements in his testimony that assert Bay State follows poor construction installation practices when replacing mains. All are completely without merit. Mr. Cavallo alleges that the Company did not meet its own standards for backfilling and bedding material as required in its operating procedures. Mr. Cavallo cites O&M procedures 4.05 (Trench Padding & Backfilling Procedure for Mains) and 10.03 (Pipe Bedding and Final Backfilling – Material Standards). Mr. Cavallo has taken these two procedures out of context. These two procedures pertain specifically to new main installations and not main repair. Bay State's O&M procedures correctly call for clean backfill and bedding for <u>new main</u> <u>installation</u> and not for the repairs witnessed by Mr. Cavallo. Bay State has always followed the natural gas industry standards for construction practices. For example, Section 10.03 of Bay State's O&M manual, which is related to pipe bedding and final backfilling, is nearly identical to the manufacturer's technical bulletin for installing new polyethylene pipe, which will be the material of choice in Bay State's SIR program. Standard industry practice for the repair of pipe is to reuse the excavated backfill material.

Q. DOES THE DEPARTMENT PIPELINE SAFETY STAFF REVIEW BAY STATE'S EXCAVATION PROCEDURES?

A. [By Mr. Cote:] The Pipeline Safety staff of the Department is very active in monitoring all of Bay State's operations, from construction techniques to meter inspections and the like. The Department staff routinely inspects Bay State's construction sites. I am unaware of Bay State having been criticized by the DTE for failing to follow its leak detection, leak repair, or its replacement main construction practices.

A. [By Mr. Bryant:] Nor have I.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. [By Messrs. Bryant and Cote:] Yes, subject to reserving the right to respond if any of Mr. Cavallo's responses to discovery indicate the need for providing additional information to the Department.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S PREFILED REBUTTAL TO THE FILED DIRECT TESTIMONY OF TIMOTHY NEWHARD

Witness:

Paul Moul, Consultant (Rate of Return, Cost of Capital)

IN SUPPORT OF BAY STATE GAS COMPANY'S REQUEST FOR INCREASE IN BASE REVENUE AND OTHER RATE MODIFICATIONS

EXH. BSG/REBUTTAL-3

JULY 29, 2005

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I. INTRODUCTION AND SCOPE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul R. Moul and I am Managing Consultant of the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062.

Q. MR. MOUL, HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted with Bay State Gas Company's ("Bay State" or the "Company") filing on April 27, 2005, and was identified as Exhibit BSG/PRM-1 and Exhibit BSG/PRM-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Company requested that I comment on and rebut the testimony presented by Mr. Timothy Newhard, a witness appearing on behalf of the Attorney General. I will also address the rate of return issue discussed in the testimony of Attorney General witness Mr. David J. Effron.

II. REBUTTAL SUMMARY

Q. WILL YOU IDENTIFY THE AREAS OF CONTROVERSY CONCERNING THE RATE OF RETURN ISSUE PRESENTED IN THE TESTIMONY OF MR. NEWHARD?

A. The central areas of dispute concerning Mr. Newhard's testimony involve: (i) whether the cost of equity proposed by Mr. Newhard, if adopted, will be adequate to accommodate capital costs during the effective period of the Performance Based Ratemaking ("PBR"); (ii) the determination of a reasonable Discounted Cash Flow cost rate; (iii) whether other methods provide a reasonable measure of the Company's cost of equity; and (iv) whether risk adjustments are necessary to the cost of equity determined from the proxy group (i.e., Comparison Group) data.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my opinion, the rate of return proposed by Mr. Newhard is inadequate to provide the Company with its cost of capital for the effective period of the Company's proposed PBR. The rate of return proposed by Mr. Newhard is deficient because:

- An 8.66% rate of return on common equity is inadequate to accommodate any upward movement in capital costs. Such an upward trend has recently developed with the progression toward higher interest rates attributed to current monetary policy and other economic factors. Indeed, in the past four (4) weeks, the yield on 10-year Treasury obligations has increased by 38 basis points (i.e., to 4.28% from 3.90%).
- An 8.66% rate of return on common equity does not come close to the returns actually expected by investors for energy utilities. Rather, the forecast return on equity expected by investors is, on average, 11.9% for Mr. Newhard's Comparison Group. Further, rates of return established in other state ratesetting proceedings in the United States recently show that the return proposed by Mr. Newhard is much too low.

Q. WHY IS IT IMPORTANT THAT THE DEPARTMENT PROVIDE THE

COMPANY WITH A RATE OF RETURN THAT ACCOMMODATES INVESTORS' EXPECTATIONS?

A. The return on equity set by the Department embodies in a single numerical value a clear signal of regulatory support for the utilities that it regulates. While cost allocations, rate design issues, and other regulatory policies relative to the cost of service and tariff issues are important considerations, the opportunity to achieve a reasonable return on equity represents a direct signal to the investment community of regulatory support. In a single figure, the authorized return on equity provides a common and widely understood benchmark that can be compared from one firm to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, etc.) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Department policies on technical matters such as the test period, rate design issues, cost of service items, and basic service adjustment clauses, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Massachusetts. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' expectations. The Department cannot ignore those expectations even in the presence of adjustments to the rate of return on common equity that can be traced to reconciling cost recovery mechanisms that may be approved as part of this case. That is to say, while I acknowledge that the Department has considerable discretion in setting the Company's rate of return on common equity that may include non-market factors, the final return should not be so low as to send a negative signal to investors that may interpret it as a punitive return finding.

Q. WHY, IN YOUR VIEW, IS THE RATE OF RETURN ON COMMON EQUITY PROPOSAL BY MR. NEWHARD TOO LOW?

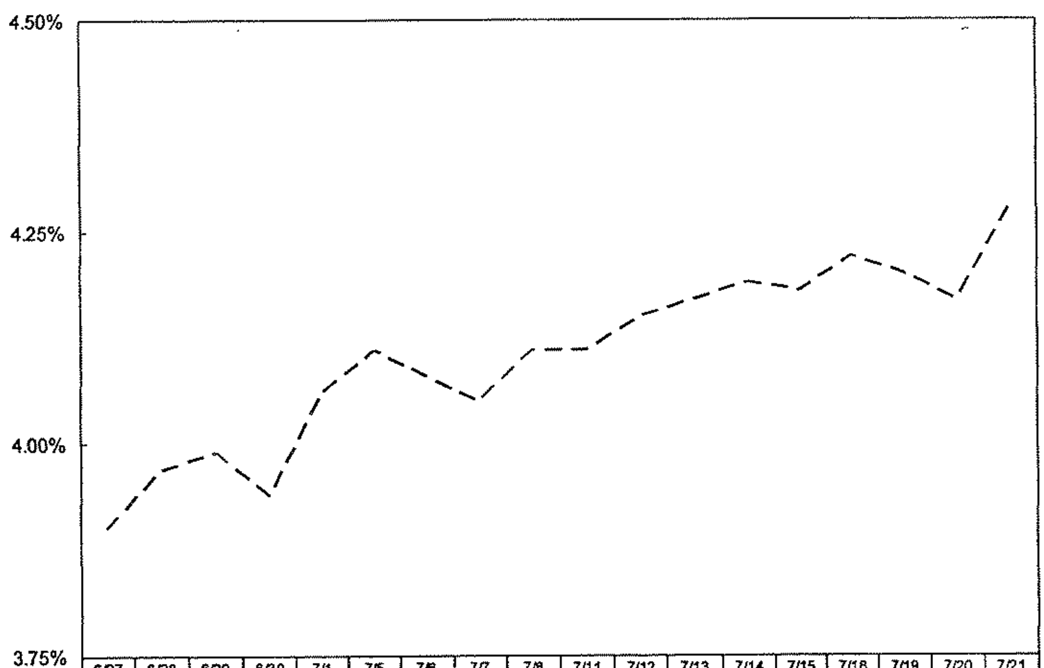
A. Among other reasons, the 8.66% rate of return on common equity being proposed by Mr. Newhard is occurring during a transition period in monetary policy. Although the PBR proposed by the Company anticipates a five-year effective period, Mr. Newhard has made no provision for the prospect of higher capital cost rates during the term of the PBR.

Q. WHAT ARE THE IMPLICATIONS OF EMPHASIZING RECENT DATA TAKEN FROM A PERIOD OF RELATIVELY LOW INTEREST RATES?

A. It appears obvious that if interest rates continue to rise from their recent low levels, the cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates.

The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy, which is now in transition. Indeed, on June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, and June 30, 2005, the

FOMC increased the Federal Funds rate in nine 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Federal Funds rate. Indeed, Sandra Pianalto, President of the Federal Reserve Bank of Cleveland, and one of the Federal Governors who serves on the FOMC has indicated that the neutral range for the Federal Funds rate is likely to be in the 3% to 5% range. With a current Federal Funds rate of 3.25%, there are likely to be more increases in the future. In addition, there has been a recent increase in Treasury yields. The yields on 10-year Treasury notes are depicted below:



	6/27	6/28	6/29	6/30	7/1	7/5	7/6	7/7	7/8	7/11	7/12	7/13	7/14	7/15	7/18	7/19	7/20	7/21
— — 10-Year	3.90%	3.97%	3.99%	3.94%	4.06%	4.11%	4.08%	4.05%	4.11%	4.11%	4.15%	4.17%	4.19%	4.18%	4.22%	4.20%	4.17%	4.28%

Moreover, the Blue Chip forecasts (see response to Information Request AG-10-6) show that the yield on 10-year Treasury Notes will average 5.4% over the period 2007-2011. As compared to recent Treasury yields shown above, the forecasts indicate a potential increase of over one percentage point in those yields.

Q. CAN YOU DEMONSTRATE HOW A RETURN ON EQUITY BELOW 10% IS UNUSUAL IN PUBLIC UTILITY RATESETTING?

A. Yes. From my experience, single digit returns on equity (i.e. those less than 10%) are unusual. According to the PUR Utility Regulatory News ("URN") issue dated December 24, 2004, authorized rates of return on common equity by state utility commissions over the period October 1, 2003 through September 30, 2004 were as follows:

	Number	Percent
Less than 10%	3	6%
10% to 10.9%	36	69%
11% to 11.9%	8	15%
Higher than 12%	5	10%

The average authorized rate of return on common equity was 10.67%, the median return was 10.50%, and the midpoint return was 11.15%, taken from the overall range of 9.60% to 12.70%. These data show that returns below 10% are unusual in rate case decisions.

Q. WHAT HAS LED TO AN UNDULY LOW (I.E., SINGLE DIGIT) RETURN ON EQUITY THAT HAS BEEN PROPOSED BY MR. NEWHARD?

A. For a variety of technical reasons that I will cover later in my rebuttal testimony, the rate of return testimony submitted by Mr. Newhard contains various misspecifications and downward biases in the models he used to measure the cost of equity. In general, the infirmities in his testimony include:

- A Discounted Cash Flow ("DCF") growth rate employed by Mr. Newhard that understates investor expected growth.
- A failure to adjust the market determined cost rate when it is to be applied to the book value capitalization.
- A failure to consider other methods/models to measure the cost of equity.
- A proposal to move to the low end of the cost of capital range based upon an unjustified reduction to the return attributed to non-regulated operations of the Comparison Group and to changes in risk for certain proposals by the Company.

As such, the recommendation of Mr. Newhard fails to meet the accepted standards of a fair rate of return.

III. DISCOUNTED CASH FLOW

Q. SHOULD ONLY A SINGLE APPROACH, SUCH AS DCF, BE USED TO MEASURE THE COST OF EQUITY FOR BAY STATE?

A. No. No single approach is sufficiently reliable to adequately establish the cost of equity without further verification. This is particularly true today given the wide swings in share values and the overall financial market uncertainty.

Q. DOES THE FREQUENT USE OF THE DCF METHOD JUSTIFY ADDITIONAL EMPHASIS ON THIS DCF METHOD?

A. No. The investment community uses the DCF model and other models in their valuation analysis of common stocks. Likewise, regulators follow a practice that includes multiple methods. The Utility Regulatory Policy in the United States and Canada survey by the National Association of Regulatory Utility Commissions ("NARUC") indicates that many regulatory agencies consider a variety of methods in the cost of equity determination (rather than just one method). Some of the other methods considered are Comparable Earnings, Capital Asset Pricing Model, and Risk Premium methods. Mr. Newhard did not provide any evidence from these other methods. Rather, he merely provided the results from two forms of the DCF. Checking DCF results with another DCF analysis provides no confirmation to verify the reasonableness of the returns. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivates investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.).

Q. WHAT FORM OF THE DCF MODEL HAS BEEN EMPLOYED IN THIS CASE?

A. The constant growth or "Gordon" form of the DCF model has been used by Mr. Newhard and me in this case. However, it must be recognized that this version of the DCF model is not without its limitations because many of the assumptions which must be made to utilize this model are simply not realistic. According to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same rate absent any change in price-earnings multiple. There is no evidence that these conditions actually prevail in the equity market. Mr. Newhard also applied a two-step DCF. The two-step DCF model has not found wide acceptance in public utility ratesetting. When it has been used by the Federal Energy Regulatory Commission ("FERC"), a more direct approach has been employed by FERC in its application rather than a formula that is solved through an iterative process by a computer as Mr. Newhard has proposed. In the case of the FERC's two-step DCF model, as is applied in natural gas pipeline cases, the short-term (i.e., five year) growth rate has been is assigned two-thirds (2/3) weight and the long-term growth rate is assigned one-third (1/3) weight in order to derive a single growth rate.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE DCF MODEL?

A. There is an element of circularity in the DCF model when applied in public utility rate cases. This is because investors' expectations for the future depend upon regulatory decisions. Therefore, the use of the DCF in rate cases ensures that regulators will continue to provide high growth utilities with a return which sustains that performance. On the other hand, the use of the DCF for low growth companies perpetuates that performance and hinders any improvement. This, then, will reinforce investors' expectations that regulators will grant returns which guarantee low growth. Due to this circularity, the DCF model may not fully reflect the true risk of a utility because the model may not deal with the high risk traits of a utility with low growth caused by poor accounting returns. If the DCF approach cannot cope with general capital market fundamentals, then either the assumptions underlying the DCF method are incomplete or the approach is not being properly implemented.

Q. ONE OF THE ASSUMPTIONS THAT IS IMPLICIT TO THE CONSTANT GROWTH DCF IS A CONSTANT DIVIDEND PAYOUT RATIO. IS THIS A REASONABLE ASSUMPTION WHEN APPLYING THE GORDON FORM OF THE MODEL?

A. No. With forecasts showing higher earnings growth rates than dividend growth rates, the expectation is that dividend payout ratios will decline in the future. According to the Value Line data utilized by Mr. Newhard, the historical and forecast dividend payout ratios are:

Years	Comparison Group
2000-04	65.9%
2005	59.0%
2006	58.5%
2008-10	55.2%

With declining payout ratios forecasted for the future, the sustainable growth form of the Gordon model is a poor choice for measuring the return on equity.

Q. REGARDING MR. NEWHARD'S CHOICE OF USING SUSTAINABLE GROWTH ESTIMATES AS ONE MEASURE OF THE DCF GROWTH RATE, DO YOU HAVE ANY FURTHER COMMENTS?

A. This special form of the DCF model essentially adjusts an assumed return on book common equity by the difference between the dividend yield on book value and the dividend yield on market value, i.e., its results are highly dependent on the market-to-book ratio analysis. A key component of sustainable growth is the assumed return on book common equity. In the case of Mr. Newhard's Comparison Group, Value Line forecasts that they will earn 11.90% on book common equity during the years 2008-10, a key period considered by Mr. Newhard.[1] Remarkably, Mr. Newhard proposes a much lower rate of return on common equity. Mr. Newhard does not explain how his Comparison Group will earn an 11.90% return on equity, if their cost of equity is set, according to Mr. Newhard, at just 8.66%. It is incumbent upon Mr. Newhard to reconcile this disparity.

Q. CAN YOU SHOW HOW THE SUSTAINABLE GROWTH FORM OF THE DCF ACCOMPLISHES THIS FEAT?

A. The major infirmity of the DCF method becomes apparent when viewing the model in its sustainable growth rate form. Mr. Newhard indicates that his preferred method for selecting the growth rate component in the Gordon form of the DCF is the "b x r" plus "s x v" approach, i.e., the sustainable growth method. This special form of the DCF merely adjusts an assumed return on book common equity by the difference between the dividend yield on book value and the dividend yield on market value. This form of the DCF cannot be viewed as a full market model because it mixes accounting returns (i.e., the E/B, or earnings book ratios shown below) and market returns (i.e., the return on market price of stock shown below) in the following manner:

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[1] The Value Line figures contain a downward bias because year-end book values are employed. The projected returns on equity would actually be higher when using average book values. This issue will be discussed in greater detail below.

$$E/B - D/B + D/P = ROE$$

where:
E = earnings per share
D = dividend per share
B = book value per share
P = price per share
ROE = return on equity

In reality, a true market model would be represented by the formula:

$$K = \frac{D_1}{P_0} + \frac{P_1 - P_0}{P_0}$$

where: D_1 = dividends per share
P_0 = current price per share
P_1 = appreciated price per share
k = cost of equity

Q. CAN YOU PROVIDE AN EXAMPLE OF THE FALLACY OF THE SUSTAINABLE GROWTH FORM OF THE DCF APPROACH?

A. Yes. Using the Value Line data relied upon by Mr. Newhard, his DCF result can be expressed in the following manner:

	Comparison Group
Return on Book Equity	11.90%
Dividend Yield on Book Value	-6.72%
Dividend Yield on Price	3.62%
Result	8.80%
External growth factor	-0.14%
DCF return	8.66%

Q. IN YOUR PRIOR EXAMPLE WHICH ILLUSTRATES THAT THE DCF RETURN IS HIGHLY SENSITIVE TO THE ASSUMED RETURN ON EQUITY (I.E., EARNINGS/BOOK RATIO) YOU SHOW THAT THE "B X R" FORM OF THE DCF IS MERELY AN ADJUSTED EARNINGS/BOOK RATIO. PLEASE EXPLAIN FURTHER.

A. Sustainable growth, along with external financing growth, is another means of describing book value per share growth. As I explained in my direct testimony, other factors also contribute to investor growth expectations in the DCF model. Even Mr. Newhard acknowledges that since market-to-book ratios recently have been above one, then book value will not be a good proxy for the growth rate in the DCF. Therefore, sustainable growth formula similarly fails in this regard. The theory of DCF suggests that, absent a change in price-earnings multiple, the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share. Hence, earnings per share form the basis for investors' capital gains yield, and earnings are the source of dividend payments to investors. In my view, sustainable growth does not represent the proper financial variable to be considered when selecting the DCF growth component. This is because utility stocks do not typically trade at book value.

Q. IN APPLYING SUSTAINABLE GROWTH, MR. NEWHARD EMPLOYED FORECASTS OF FUTURE GROWTH FROM RETAINED EARNINGS PUBLISHED BY VALUE LINE. DO THESE INPUTS PROVIDE AN UNBIASED RESULT WHEN COMPUTING RETENTION GROWTH?

A. No. First, Mr. Newhard has employed two different methods of measuring historical and forecast growth from retained earnings. For his historical analysis, he makes an independent calculation that subtracts the dividend per share from the earnings per share and divides the remainder by the average book value per share. For the forecasts, he uses Value Line published numbers and does not verify them. When using the Value Line forecasts, it is necessary to adjust those returns from year-end to average book common equity. Without an adjustment to convert the Value Line forecast return from year-end to average book values, there is a downward bias in the results, because with an increasing book value caused by retention growth, the average book value will be less than year-end book value. Indeed, the year-end book value will already contain a portion of the earnings that are not paid out as dividends, which means that the earnings for a particular year are measured by the book value that already reflects part of those earnings. When FERC employs these data, it adjusts the year-end returns to derive the average yearly return with the formula 2 (1 + G) / (2 + G) that is computed with the growth in the equity component (see 92 FERC ¶ 61,070). To be consistent with Mr. Newhard's historical analysis, an adjustment is necessary to state the forecasts on an average book value basis.

Q. CAN YOU CORRECT MR. NEWHARD'S SUSTAINABLE GROWTH RATES USING FORECAST DATA AND COMPARE THEM WITH THE FORECAST GROWTH IN BOOK VALUE?

A. Mr. Newhard's analysis provides a very unsatisfactory comparison in this regard. First, I have made the correction necessary to state the forecasts on an average book value basis. Those corrections are shown below:

	Years 2008-10						
Company	Book Value per Share	Earnings per Share	Dividends per Share	Growth From Retained per Share	(s x v)	Sustainable Growth Rate	Book Value per Share Growth
AGL Resources, Inc.	$ 22.50						
	$ 23.90	$ 2.75	$ 1.35	6.03%	0.14%	6.17%	8.00%
New Jersey Resources Corp.	$ 26.67						
	$ 28.40	$ 3.25	$ 1.52	6.28%	-1.00%	5.28%	11.00%
Piedmont Natural Gas Co.	$ 13.25						
	$ 13.75	$ 1.60	$ 1.10	3.70%	-0.53%	3.17%	7.50%
South Jersey Industries, Inc.	$ 14.95						
	$ 15.80	$ 2.00	$ 1.15	5.53%	0.68%	6.21%	6.00%
WGL Holdings, Inc.	$ 19.20						
	$ 20.40	$ 2.60	$ 1.40	6.06%	0.01%	6.07%	4.00%
Group Average				5.52%	-0.14%	5.38%	7.30%

By removing the downward bias caused by the use of end of period, rather than the average book values, the growth from retained earnings shown above (i.e., 5.52%) increase by 0.12% (5.52% - 5.40%) as compared with Mr. Newhard's biased figures (i.e., 5.40%). Even with this correction, the sustainable growth rates determined by Mr. Newhard (see Mr. Newhard's Schedule 3), misspecify the growth in book value forecast by Value Line. As shown above, Value Line forecasts book value per share will grow on average by 7.30% for the Comparison Group. As such, even the corrected sustainable growth rate of 5.38% severely understates investors' growth expectations in this regard.

Q. WHAT DCF RETURN WOULD BE INDICATED USING THE VALUE LINE FORECAST OF BOOK VALUE PER SHARE GROWTH?

A. Using Mr. Newhard's form of the DCF and his dividend yield, the return would be:

$$D/P\ (1 + .5g)\ +\ 9\ \ =\ \ k$$

$$3.62\%\,(1.0365)\ +\ 7.3\%\ =\ 11.05\%$$

Q. MR. NEWHARD ALSO SUBMITS A TWO-STEP DCF ANALYSIS FOR HIS COMPARISON GROUP. ARE THE ASSUMPTIONS THAT ARE BUILT INTO THIS ANALYSIS REASONABLE?

A. No. Mr. Newhard assumed that only two variables affect investor expectations concerning their required return and for those variables, only three sources of information can be considered. In essence, Mr. Newhard has presented an overly simplified expression of a far more complex set of expectations and variables considered by investors.

Q. PLEASE EXPLAIN.

A. First, a two-step DCF model contains some very unrealistic assumptions of investor behavior. Mr. Newhard has not shown that additional steps are considered by investors. As explained in my direct testimony (see page 27), there is a strong likelihood that some transitional step lies between the five-year growth rate and a steady-state growth assumed to prevail in perpetuity after the fifth year. Also, Mr. Newhard has not established that growth rate cycles repeat in the future. Second, Mr. Newhard has introduced a number of biases into the input variables that he used in his two-step analysis.

Q. DO YOU HAVE ANY COMMENTS ON MR. NEWHARD'S GROWTH RATES TAKEN FROM ANALYSTS' FORECASTS FOR HIS TWO-STEP DCF?

A. Yes. Mr. Newhard relied upon Thomson Financial (i.e., First Call) and Zack's earnings growth rates for his first-step growth rates. Without proper justification, he ignores forecasts of earnings growth from Value Line. This omission by Mr. Newhard is especially perplexing given the fact that he relied exclusively upon the Value Line data in the development of all aspects of his sustainable growth rate calculation. If Value Line provides complete support for the sustainable growth rate, it cannot be ignored for the purpose of forecasts of earnings growth. Put simply, Mr. Newhard cannot have it both ways, i.e., exclusive use of Value Line for sustainable growth and the omission of the Value Line forecasts of earnings per share growth.

Q. WHAT WOULD HAVE BEEN THE FIRST-STEP GROWTH RATE WHEN INCLUDING THE VALUE LINE FORECASTS OF EARNINGS GROWTH RATE.

A. Those results are shown below:

Comparison Companies	Thomson Financial	Zack's	Value Line	Average
AGL Resources	4.20%	4.67%	5.00%	
New Jersey Resources	5.33%	6.00%	8.00%	
Piedmont Natural Gas	4.98%	5.13%	7.50%	
South Jersey Industries	6.00%	6.00%	5.50%	
WGL Resources	3.80%	4.00%	6.50%	
Average	4.86%	5.16%	6.50%	5.51%

Q. HAS MR. NEWHARD PROVIDED ADEQUATE JUSTIFICATION FOR HIS SELECTION OF THE SECOND-STEP GROWTH RATE THAT HE PROPOSED?

A. No. Mr. Newhard is simply incorrect in his choice of the forecast growth in GDP as his second-step growth rate. As explained in my direct testimony (see pages 28-29), forecasts of GDP growth can be used as a proxy for revenue growth, but it is not a proper representation of earnings growth. I fully discussed the construction and components of the GDP in my direct testimony (see pages 28-29), and I will not repeat that again here. Suffice it to say, forecasts of growth in corporate profits provide the correct representation of second-step growth in Mr. Newhard's DCF analysis.

Q. WHAT SECOND-STEP GROWTH RATE SHOULD BE USED FOR THIS PURPOSE?

A. The Blue Chip forecast of growth in corporate profits is 6.3% for the years 2012-16 (i.e., representing the most distant forecast available). The growth rate exceeds the growth rate in GDP for reasons explained in my direct testimony (see pages 28-30). The divergence in growth between the GDP and corporate profits is not a recent phenomenon. Corporate profits have exceeded GDP growth historically on average for the past 72 years.[2] Hence, the correct second-step growth rate is 6.3% for use in Mr. Newhard's two-step DCF model.

Q. WHAT ARE THE RESULTS OF MR. NEWHARD'S TWO-STEP DCF ANALYSIS WHEN CORRECTED IN THE MANNER PREVIOUSLY DESCRIBED BY YOU?

A. Using the spreadsheet model developed by Mr. Newhard (i.e., Information Request

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[2] Obviously, growth in corporate profits are negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP during the years 1932 to 2004.

BSG-AG-1-28), without altering it for the additional infirmities described previously, the result would be __% when employing a 5.51% first-step growth rate and a 6.3% second-step growth rate.[3]

Q. MR. NEWHARD MAKES NO ADJUSTMENT FOR THE FINANCIAL RISK ATTRIBUTED TO THE DIVERGENCE OF MARKET CAPITALIZATION AND BOOK VALUE CAPITALIZATION. PLEASE COMMENT.

A. It must be recognized that, in order to make the DCF results relevant in the ratesetting context, the market-derived cost rate cannot be used without modification. The importance of the leverage modification to the DCF results was fully supported in my direct testimony, wherein it was shown that the market value of the Gas Group's capitalization was much higher than its book value. To make the market-derived DCF results applicable in the ratesetting context, it is necessary to account for the higher financial risk that arises from the lower common equity ratio measured by book value capitalization as compared to the higher common equity ratio measured by market capitalization. Because book value capital structures are used instead, my adjustment procedure is required.

The formulas developed by Nobel laureates Modigliani and Miller are designed to account for differences in financial risk among varying capital structures (i.e., related to the proportions of debt and equity in the capital structure). The issue addressed by my adjustment is related solely to financial risk (i.e., the percentage of borrowed funds in the capital structure). In addition, the DCF calculations presented

3 This figure to be finalized when Mr. Newhard fully responds to the Company's information request.

by Mr. Newhard and me produce the returns that investors expect on their market value. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. The assumptions implicit in the model were described in my direct testimony. By rearranging the terms, we obtain the familiar DCF equation: $k = D/P+g$. All of the terms in the DCF equation represent investors' assessments of expected future cash flows that they will receive in relation to the value that they set for a share of stock ("P"). The need for the leverage adjustment arises when the results of the DCF model ("k") are to be applied to an equity ratio that is different than the one shown by the market price ("P"), i.e., in this instance, the equity ratio calculated from the book value capitalization. My leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value, nor does it target any particular market-to-book ratio.

Further, the leverage adjustment adds stability to the DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. MR. NEWHARD ALSO PROVIDES SOME DCF RETURNS BASED ON STOCK PRICES OF NISOURCE. IS THIS DATA RELEVANT FOR THIS CASE?

A. No. NiSource market data does not provide a reasonable basis to measure the return for a gas distribution utility in this case. The natural gas distribution business of NiSource is represented by only 37.3% of identifiable assets. This percentage is significantly below the range of 81.85% to 95.19% of natural gas distribution assets for the Comparison Group companies (see response to Information Request D.T.E. 3-11). The diverse nature of the businesses of NiSource and its operations in gas transmission and storage (18.0% of assets), electric operations (18.3% of assets), and corporate and other operations (26.4% of assets) makes it unsuitable for measuring the cost of equity for Bay State.

IV. RESPONSE TO ADJUSTMENTS PROPOSED BY MR. NEWHARD

Q. MR. NEWHARD DEVELOPS A RANGE OF THE COST OF EQUITY FROM HIS COMPARISON GROUP AND ARGUES THAT THE RETURN FOR BAY STATE SHOULD BE SET AT THE LOWER END OF HIS RANGE. IS THIS PROPOSAL REASONABLE?

A. No. Mr. Newhard seems to be arguing for the low end of his range for two reasons. First, he suggests that the business activities of the Comparison Group companies include non-regulated endeavors, and hence the cost of equity derived from the group average data somehow overstates the return necessary for utility operations. Mr. Newhard provides no empirical support in his testimony for this assertion. Indeed, any adjustment in this regard is not justified because the vast majority of the operations of the Comparison Group companies are regulated, i.e., non-regulated operations represent a small minority of their investment (e.g., regulated assets represent 88% of all business segments for the Comparison Group). In addition, market evidence indicates that no such adjustment in this regard is warranted. This is shown by the Value Line statistics for the companies within the Comparison Group. These are shown below:

Company	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Techincal Rank
AGL Resources, Inc.	3	2	B++	100	0.85	3
New Jersey Resources Corp.	4	2	B++	100	0.75	3
Piedmont Natural Gas Co.	5	2	B++	100	0.75	4
South Jersey Industries, Inc.	4	2	B++	100	0.60	3
WGL Holdings, Inc.	4	1	A	100	0.75	3
Average	4	2	B++	100	0.74	3

As indicated from the statistics shown above, Piedmont Natural (a company with almost all of its operations devoted to the utility) is very similar to the Comparison Group average data, which indicates no adjustment is necessary for non-regulated businesses in determining a utility's cost of equity.

Mr. Newhard's second reason for moving to the low end of his range seems to rest on the various adjustment mechanisms available or proposed by Bay State.

Q. MR. NEWHARD CLAIMS THAT THE PPM, AS WELL AS OTHER ADJUSTMENT MECHANISMS PROPOSED BY BAY STATE WARRANT A REDUCTION IN THE COMPANY'S RATE OF RETURN ON COMMON EQUITY. SHOULD HE HAVE INVESTIGATED THIS MATTER FURTHER?

A. Yes. Had he done so, I doubt that certain assertions made by Mr. Newhard would have been considered. For example, with regard to the commodity cost of gas and recovery mechanisms for environment remediation costs, Bay State has proposed nothing unique by reference to other gas utilities. Further, many other gas utilities have alternative means to deal with some of the other issues, such as pension and other post-retirement benefits discussed above. Further, Bay State lacks a weather stabilization clause that is common for most companies in Mr. Newhard's Comparison Group. Mr. Newhard's analysis is clearly one-sided because he focuses on alleged risk-reducing features of the Company's proposals, but ignores factors that increase the Company's risk by reference to the Comparison Group. Finally, Mr. Newhard should have familiarized himself with the revenue provisions that establish cost recovery for Atlanta Gas Light (a subsidiary of AGL Resources) prior to making certain of his claims. Atlanta Gas Light collects its revenues through a demand charge that is not volumetrically determined. Also, it does not provide end-users with any commodity. Hence, Atlanta Gas Light's revenues are not subject to variations due to uncollectibles, the cost of gas, lost margins due to conservation measures, and weather variations. Moreover, the pipeline replacement program ("PRP") that has been in effect since 1998 for Atlanta Gas Light, provides recovery of the capital costs for the replacement of cast iron and unprotected steel mains on a per customer basis (i.e., not volumetrically determined).

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY IN RESPONSE TO MR. NEWHARD.

A. In my opinion, Mr. Newhard's proposed cost of equity is far too low relative to investors' expectations. Mr. Newhard erroneously proposed setting the Company's rate of return on common equity at the low end of the range based upon an unjustified reduction in the return due to certain proposals made by the Company in this case.

Q. DOES THIS CONCLUDE THE TESTIMONY YOU ARE PROVIDING IN REBUTTAL TODAY?

A. Yes, subject to reserving my right to provide additional necessary information following receipt and review of Bay State's discovery of Mr. Newhard.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S PREFILED REBUTTAL TESTIMONY TO THE FILED DIRECT TESTIMONY OF JACOB POUS

Witness:
Earl Robinson, Consultant (Depreciation)

IN SUPPORT OF
BAY STATE GAS COMPANY'S
REQUEST FOR INCREASE IN BASE REVENUE AND
OTHER RATE MODIFICATIONS

EXH. BSG/REBUTTAL-4

JULY 29, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Earl M. Robinson and my business address is Weber Fick & Wilson Division of AUS Consultants – Utility Services, 275 Grandview Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU THE SAME EARL M. ROBINSON THAT PROVIDED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the positions taken by the Attorney General's witness, Jacob Pous.

Q. ARE THE DEPRECIATION PROPOSALS SET FORTH IN YOUR EXHIBITS BSG/EMR-1 AND BSG/EMR-2 FOR THIS PROCEEDING REASONABLE AND APPROPRIATE?

A. Yes. The Company's proposed depreciation rates are well founded and fully supported by a detailed analysis of the history of the Company's plant in service and the factors anticipated to impact the Company's property over the remaining lives of its asset groups. In contrast, Mr. Pous chose to address only two property categories within the Company's various property groups. It appears that Mr. Pous addressed only those two property categories because these are areas where he could most easily effect the greatest impact on the Company's depreciation proposal.

Q. MR. POUS STATES THAT THE INFORMATION PROVIDED BY THE COMPANY IS INADEQUATE TO SUPPORT THE COMPANY'S

PROPOSED NEGATIVE NET SALVAGE FACTORS (POUS TESTIMONY, P. 9 lines 27-29). DO YOU AGREE?

A. No. The Company's net salvage data provided to Mr. Pous was a complete database of all of the Company's available historical net salvage data. Further, the depreciation study report (Exhibit BSG/EMR-2) contains the detailed historical analysis plus the forecasted net salvage calculations for all categories of the Company's depreciable property. Mr. Pous is incorrect in his assertion that the historical and forecast analysis of net salvage trends does not provide adequate support for the proposed net salvage factors.

My recommended net salvage factors are based on Bay State's net salvage and cost of removal data. They are also more conservative than net salvage factors that have resulted from other gas industry depreciation studies when considering the related average service life of the property group being analyzed. Specifically with regard to Account 376 - Gas Distribution Mains, the proposed net salvage for Bay State is negative 15 percent, while the net salvage percentages in studies I have completed for other operating gas companies (as well as the percentages utilized by gas distribution companies in New England that I obtained), range from negative 15 to negative 75 percent. (Rebuttal Exhibit EMR-R3).

With regard to Account 380 - Services, the proposed net salvage for Bay State is negative 170 percent, while other New England based gas distribution companies' net salvage parameters are in the range of negative 60 percent to negative 175 percent, with three companies comparable to the net salvage proposed for Bay State. Even more important is the fact that the average service life for Bay State's Account 380 – Services is longer than that for the other New England based gas distribution companies. Given the longer period of time between the original installation year and the subsequent retirement of services, it is apparent that Bay State's negative net salvage percent for Account 380 - Services should be higher than those companies that are utilizing shorter average service lives. (Rebuttal Exhibit EMR-R3).

Q. DOES MR. POUS CORRECTLY DEFINE NET SALVAGE?

A. Yes. Mr. Pous states that, "Net salvage is simply the value received for the sale, reuse, or reimbursement of retired property (gross salvage) less ***the cost of retiring such property*** (cost of removal), whether the retirement reflects demolition of the item of plant or only the accounting transaction for retiring an item of property abandoned in place." (Emphasis added) (Pous testimony, p. 9 lines 11-14).

However, in his proposed future negative net salvage factors for Account 376 - Mains and Account 380 – Services, Mr. Pous fails to properly recognize the true cost to retire assets at the ultimate end of their life.

Q. DO YOU HAVE A GENERAL COMMENT REGARDING MR. POUS' NET SALVAGE RECOMMENDATIONS?

A. It appears that Mr. Pous is most concerned with the level of the depreciation expense change as opposed to whether the level of net salvage percent is appropriate, as he makes a point to identify how much of a reduction to depreciation expense his proposed net salvage percent adjustment produces as opposed to spending more time to investigate the underlying data.

Although Mr. Pous focuses on only the past ten years of the Company's net salvage experience for mains, during that ten-year period the Company's actual net salvage experience exceeded the current underlying net salvage factor of negative 10 percent, six (6) out of the ten (10) years. (Exhibit BSG/EMR-2, p. 7-19). Also, Mr. Pous gave no consideration to the fact that future cost of removal (as confirmed by the future net salvage forecast analysis) will continue to increase. (Exhibit BSG/EMR-2, p. 7-21). Moreover, it can be anticipated that the Company's steel replacement program will generate additional levels of future retirement cost.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. POUS' CRITICISM OF YOUR USE OF FUTURE NET SALVAGE FORECAST ANALYSIS INCLUDED WITH THE COMPANY'S NET SALVAGE ANALYSIS?

A. Mr. Pous misstates how I have used the forecasted net salvage data. (Pous testimony, p. 12).

In recent depreciation studies, I have included forecasts of future net salvage in the overall depreciation analysis. These forecasts assist in determining a reasonable estimate of the level of future net salvage that is anticipated to occur as of the end of the life of the existing plant in service. The forecasted information, however, is simply an additional analytical tool and source of additional information to be considered in arriving at the future net salvage estimate. The forecasts themselves do not determine the net salvage amount I recommend. The extent to which the forecasted net salvage is incorporated into the proposed depreciation rate is simply an indication of how conservative the estimate is that is used in developing the proposed depreciation rate for each of the applicable plant accounts.

Mr. Pous states that net salvage amounts will be significantly influenced by "productivity gains, different mixes of piping retired, different rates of abandonment, the concept of economies of scale, the wide dispersion that may transpire in the actual physical activity due to timing and location of retirements, the level of overtime that may vary from year to year, as well as other factors." (Pous testimony, p. 12 line 28 – p.13 line 4).

My analysis is based upon the Company's complete retirement/net salvage history (the widest available source of Company historical data). Items such as types of piping and rates of retirement are likely to have little, if any, impact on future cost relationships as compared to historical relationships. That is, the historical cost of removal is already an accumulation of data on a diverse range of materials within the various property groups. Likewise, the dispersion of future retirements is anticipated to generally follow the pattern of prior activity.

Regarding Mr. Pous' statement as to potential benefits from future economies of scale, he suggests that the Company's property retirement process is similar to an industrial process where employees gain significant efficiencies through improved knowledge, experience, and workflows. Such benefits simply will not occur in the retirement process because retirements will continue to occur throughout the Company's large distribution area. Furthermore, Company work crews will continue to change and there are often specific circumstances encountered that complicate the retirement process for any particular project such as soil conditions, tree roots, and other utility infrastructure in the affected area.

Mr. Pous' claim that "Mr. Robinson's approach still produces a mismatch that results when one requires cost of removal expressed in future dollars to be collected from current customers in current dollars" is a mischaracterization of real world events. (Pous testimony, p. 13 lines 9-12). The cost of removal (retirement) always has been, and always will be, the relationship between the end of life cost and beginning of life cost. Recovery of invested capital through depreciation rates must appropriately reflect the recovery of the total life cost of the assets that are being consumed by the Company's customers in the process of receiving service. Depreciation expense is, in fact, designed to collect anticipated future costs of retirement from current customers.

Q. HOW HAVE YOU USED THE RESULTS OF YOUR NET SALVAGE FORECAST ANALYSIS?

A. The importance of the forecast analysis is to provide an additional tool bearing upon the ultimate total life cost of the Company's property. Recently, increased focus has been placed in depreciation studies on the full recognition of all applicable operating plant costs (both the beginning and end of life costs) for each property group being depreciated. Therefore, in recent studies, forecasts of future net salvage have been calculated and included with the depreciation analysis. These forecasts assist in determining a reasonable estimate of the level of future net salvage that is anticipated to occur as of the end of the life of the existing plant in service. This information is simply an additional analytical tool and source of information to be considered in arriving at the future net salvage estimate. Furthermore, the results of the forecast analysis generally serve to reinforce the assumption that the current level of experienced net salvage should routinely be the floor, or minimum level, for the estimated future net salvage percent.

Selecting a more conservative net salvage amount than what is indicated by the forecast analysis does not mean the forecast analysis is flawed. It simply means that it is prudent not to move all at once to the results indicated by the forecasts. Gradualism, such as this, is a concept specifically endorsed by Mr. Pous in his testimony.

Q. **IS MR. POUS' DATA PLOTTING OF THE FORECAST ANALYSIS (POUS TESTIMONY, P. 15), CORRECT?**

A. Absolutely not. Mr. Pous states, "If Mr. Robinson's model were valid, one could plot the percentage relationship for cost of removal to retirements against the age of the retirements and observe a line sloping upward as age increase [SIC]." (Pous testimony, p. 14 lines 10-12).

There are errors in Mr. Pous' analysis. His first error is the use of net salvage in lieu of cost of removal in plotting the property retirement age to cost of removal relationship. The use of negative net salvage (including gross salvage) by Mr. Pous (Pous testimony, p. 15) incorrectly skews the age/percentage relationship and does not represent the cost of removal. Secondly, and equally important, is the fact that the Company's cost of removal data does not permit identification of age specific cost of removal data. That is, there is no direct linkage between the specific age and dollar amount of a retirement to the corresponding cost of removal amount in the Company's data. The salvage data is simply the accumulation of the yearly cost of removal transaction data. That data is then compared to the year's aged retirements. It is apparent that the data is an accumulation of retirements of different ages and costs of removal of differing levels. For example, the cost of removal experience within the Company's data, while relative to average retirements (for example with an average age of 20 years) may be applicable to underlying retirements that occur at 10 and 30 years (which result in a 20 year average age). Since the cost of removal is not identified by specific age, a specific age analysis cannot be performed.

Despite such concerns, correctly capturing the relationship of the Company's cost of removal data and the average age of retirements with a linear regression analysis does produce a line sloping upward as age increases (as shown in Rebuttal Exhibit EMR-R1). This linear forecast of cost of removal is, in fact, valid. Mr. Pous simply used incorrect data to complete his analysis and data plotting.

Q. PLEASE COMMENT ON MR. POUS' CLAIM THAT YOUR CONSIDERATION OF THE COMPANY'S EXPERIENCE AND EXPECTATIONS HAS "NO MEANINGFUL IMPACT." (POUS TESTIMONY, P. 16 LINES 4-5).

A. My reference in the depreciation study to consideration of "the Company's experience and expectations" relates directly to the Company's salvage experience and expectations that were arrived at via the detailed historical analysis and preparation of the future net salvage forecast. For example, within Account 380, while the overall salvage analysis indicates average net salvage of negative 171 percent, shrinking band analysis identifies that more recent periods have experienced net salvage in excess of negative 200 percent. In addition, the future net salvage forecast analysis was considered in estimating the proposed negative 170 percent net salvage. (Exhibit BSG/EMR-2, pp. 7-26, 7-27). Mr. Pous simply fails to acknowledge the fact that the Company will be experiencing additional levels of end of life negative net salvage relative to the property currently in service.

Q. PLEASE COMMENT ON MR. POUS' STATEMENT THAT THE COMPANY ADMITS THAT IT "NORMALLY ACCOUNTS FOR WHAT IT MIGHT IDENTIFY AS THE COST OF REMOVAL AS THE COST OF A NEW INSTALLATION" AND THAT "THIS IS PROPER ACCOUNTING." (POUS TESTIMONY, P. 16 LINES 6-8).

A. The Massachusetts Uniform System of Accounts for Gas Companies (Revised Edition, Effective January 1, 1961) states that cost of removal associated with the retirement of plant in service shall be charged to Account – 254, Reserve for Depreciation. Mr. Pous is incorrect when he states that charging cost of removal to new installations "is proper accounting." (Pous testimony, p. 16 lines 7-8). A copy of the applicable account description from the Massachusetts Uniform System of Accounts for Gas Companies is included as Rebuttal Exhibit EMR-R2.

The Company's accounting practice that may charge, in certain circumstances, the cost of removal to new installation may need to be modified.

This current practice, however, would only result in an understatement of the Company's negative net salvage amounts.

Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO MR. POUS' CRITIQUE OF THE PROPOSED NEGATIVE NET SALVAGE FACTOR FOR ACCOUNT 380 - SERVICES?

A. Mr. Pous was provided with a complete database of historical information related to the Company's experience with regard to services. Summaries of the net salvage database and analysis results were also provided in Section 7 of Exhibit BGS/EMR-2. The narrative in my depreciation study provides an explanation of the range of the data and the factors considered in developing the Company's proposed net salvage. Mr. Pous implies, however, that the depreciation analysis process can simply be expressed in a formula by developing averages of various selected scenarios to arrive at the resulting negative net salvage factor. The interpretative process of estimating depreciation parameters cannot be turned into a simple arithmetic function.

Q. WITH REGARD TO ACCOUNT 380 – SERVICES, MR. POUS APPEARS TO OBJECT TO THE NEGATIVE NET SALVAGE THAT IS GREATER THAN THE ORIGINAL COST OF THE INVESTMENT. PLEASE COMMENT.

A. For this account, the requested negative net salvage is greater than the level of the original cost of the plant when placed in service. It is obvious that Mr. Pous fails to recognize that the cost for the retirement of services (as related to the original cost to install the services) is high. It is not unusual for the net salvage cost of services to exceed the original cost of the plant when placed in service.

Mr. Pous also comments that the negative net salvage percentage for services is far greater than the percentage for mains. (Pous testimony, p. 18 lines 20-26). The cost of removal percentage for services will be far greater than that experienced for mains because of the greater level of retirement activity that is required for services compared to a far smaller level of service property investment than exists for mains. That is, the relatively short service must be disconnected and purged while such disconnections for mains occur at much longer lengths for pipe with a much higher original cost. In addition, Mr. Pous seeks to correlate the relationship of the cost of removal for the Company's services and mains to services versus mains cost of removal relationship in the gas industry. (Pous testimony, p. 18 lines 17-20). Such a comparison is not meaningful because the gas industry data that Mr. Pous uses is simply a group of averages as opposed to individual company level data for comparable property groups.

Q. MR. POUS IMPLIES THAT ONE YEAR'S (1994) NET SALVAGE PERCENT FOR SERVICES LEADS TO INCORRECT OVERALL RESULTS. PLEASE COMMENT.

A. Mr. Pous focused on the 1994 net salvage of negative 1,724 % in an attempt to discredit the Company's historical net salvage data for services (Pous testimony, p. 20 line 11) (Exhibit BSG/EMR-2, p. 7-25). If Mr. Pous had reviewed the data that is contained on the salvage analysis schedule he refers to, he would have observed that the reason for the extremely high net negative salvage was the fact that the 1994 retirements were extremely low in comparison to years prior to, and after, 1994. The high negative net salvage is simply caused by the timing of the retirements. In the response to information request AG-8-9, the Company indicated that the net salvage data was not necessarily synchronized. While it is the Company's goal to record related retirements and net salvage transactions in the same accounting periods, variances can and do exist.

Q. MR. POUS STATES THAT FOR SERVICES "THE REVIEW OF THE HISTORIC DATABASE DURING THE PAST 10 YEARS INDICATES THAT THREE OUT OF THE FOUR HIGHEST DOLLAR LEVELS OF RETIREMENT ACTIVITY CORRESPOND TO THE LOWEST LEVELS OF NET SALVAGE PERCENTAGES EXPERIENCED DURING THE 10 YEAR PERIOD." (POUS TESTIMONY, P. 21 LINES 16-18). PLEASE COMMENT.

A. Mr. Pous should have realized that much of the lower percentage levels of net salvage for services that he references follow immediately the high 1994 net salvage percent of negative 1,724 percent. It is therefore the resulting net salvage percentage calculations are simply a function of the timing of the closing of the retirement and net salvage entries.

Mr. Pous states that I have testified to lower net salvage values for services in cases in other jurisdictions, namely, Kansas and Kentucky. (Pous testimony, p. 23 lines 13-17). First, while net salvage factors in those cases were less negative for services than the level proposed for Bay State, the related average service lives for services in those cases were only approximately 50 to 60 percent of the length of the average service lives being recommended for Bay State Services. Accordingly, one would expect that the negative net salvage in those cases would be substantially less negative than what is required for Bay State. In addition to those cases I have prepared depreciation studies, which have resulted in negative net salvage percentages for Services equal to, or higher than, what I recommend for Bay State.

The Company's proposed negative 170 percent net salvage is appropriate, well supported, and is consistent with other gas operating companies within the New England region.

Q. **IS MR. POUS' RECOMMENDED NEGATIVE 110 PERCENT NET SALVAGE, OR THE MANNER IN WHICH HE ARRIVED AT THE RECOMMENDATION, APPROPRIATE FOR ACCOUNT 380 - SERVICES?**

A No. Mr. Pous' recommended value is equal to the average of the 4 years during the past 10 years that experienced the largest level of dollar retirement activity. (Pous testimony, p. 23 lines 23-24).

Mr. Pous simply ignored all of the Company's remaining net salvage data analysis and selected four recent years (within the past ten years) with the lowest negative net salvage percent in developing his recommended net salvage factor. (Exhibit BSG/EMR-2, p. 7-25). He gave no consideration to factors that contributed to the amounts that he utilized, nor did he request any specific information about the basis of the retirements and relative net salvage amounts he selected.

Q. **WHAT COMMENTS DO YOU HAVE WITH REGARD TO MR. POUS' AVERAGE SERVICE LIFE RECOMMENDATION FOR ACCOUNT 376.4 - PLASTIC MAINS?**

A. Mr. Pous would have the Department believe, through his graphical presentation and discussion, that his service life parameter recommendation is the result of a more comprehensive and correct interpretation of the data and expectations for the property group. It takes only a limited investigation to recognize that Mr. Pous' recommendation is simply results driven. First, with regard to the graphical presentations, Mr. Pous plots the curves on a very large scale which makes the variances (from age 0 to age 25) between his recommended Iowa 68-S1.5 life and curve and the Iowa 55-S2 life and curve underlying the proposed depreciation rates in the depreciation report (Exhibit BSG-EMR-2) appear far larger than they really are. While there are some limited variances in the points referenced by Mr. Pous, the more important fact is that he admits that he totally ignores the data beyond 25 years of age. With regard to his analysis of the Account 376.4 - Plastic Mains data, Mr. Pous initially states on page 31 of his testimony:

> The actual data declines from approximately 97% surviving around 25 years of age to 80% surviving in the 26th year of age. (footnote omitted). While this decline from 97% surviving to 80% surviving is depicted in the data, it is based on a retirement of only $3,283.47. (footnote omitted) .... *In other words, both Mr. Robinson and I recognize the inappropriateness of relying on the sharp decline*

> *between ages 25 and 26* due to an extremely small dollar level of retirement that may be atypical or unusual, and not indicative of what one would expect in the future. This represents the concept of materiality, which addresses whether the data is adequately robust in order to rely on it as being representative.

(emphasis added) (Pous testimony, p. 31 line 4 – p. 32 line 4). Mr. Pous then goes on to state on page 32 of his testimony:

> While I do not know the specific underlying rationale for Mr. Robinson's decision to also ignore this data, my review of the data clearly identifies that the retired plant corresponds to the second year in history when the Company began the installation of plastic mains. The industry experienced problems with early plastic pipe installed during this same period. Some of the industry problems, which resulted in abnormal early retirements, were due sometimes to installation practices, or to poor chemical composition of plastic resin. *The key point is that there is a logical basis to completely ignore the dramatic change in the survivor curve between the ages of approximately 25 and 26 even without specific confirmation from the Company regarding the actual underlying circumstance of that retirement.*

(emphasis added) (Pous testimony, p. 32 lines 9-19).

Mr. Pous incorrectly assumes I "recognize the inappropriateness of relying on the sharp decline." (Pous testimony, p. 31 line 12 – p. 32 line 1). It is not appropriate to completely ignore any data, as Mr. Pous does. Mr. Pous discusses the likelihood that plastic main retirements were related to industry problems with early vintage plastic mains (plastic mains started to be installed during the late 1960's). While some limited levels of early plastic vintage retirements occurred, far greater portions of the plastic mains retirements occurred during years 1978 and later. These significant levels of plastic main retirements have occurred as a result of all causes of retirements (not just physical attributes) and will continue to occur at increasing levels during future years. Also, Mr. Pous was provided the entire depreciation database, which he apparently did not review in detail. He also did not request any specific details about the early vintage retirements.

A more significant factor that supports the service life parameter recommendation set forth in the depreciation study (Exhibit BSG-EMR-2), is the results of the various data analysis completed relative to this property group. I analyzed all the historical data points (Rebuttal Exhibit EMR-R4, pages 1 of 4 and 2 of 4) relative to plastic mains. The result of this analysis (actual "least squares" best fit curve) is an indicated service life represented by an Iowa 41-S2 life and curve. While I interpreted that the level of retirements (beyond age 25) was likely proportionately somewhat larger than would be experienced in coming years, I also estimated that future retirements from older vintage aged retirements will nevertheless continue to occur, albeit at a proportionately somewhat lower level. Accordingly, to estimate the ultimate proposed service life for this property category, I prepared an additional analysis (as shown on Rebuttal Exhibit EMR-R4 pages 3 of 4 and 4 of 4). In that analysis I truncated the retirement data at age 25 (thereby excluding the retirements of 25 years of age and older) and reviewed the indicated average service life for the Iowa S2 curve (the service life pattern indicated from the overall analysis). This analysis indicated that an Iowa 53-S2 life and curve was appropriate and supports my subsequently estimated Iowa 55-S2 life and curve for plastic mains.

In addition, a review of the AGA-EEI industry depreciation survey indicates that the mean average service life for the overall Account 376 is 55 years. The depreciation study results are (by material type) even more compelling relative to numerous service life studies that have been performed within the gas industry (and for selected companies within the New England region) during recent years. Rebuttal Exhibit EMR-R3 summarizes the results of those various studies and identifies that average service lives of fifty-five (55) years and less were routinely produced for plastic distribution mains.

Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO MR. POUS' CRITICISM OF THE ESTIMATED IOWA 55-R4 LIFE AND CURVE IN THE DEPRECIATION STUDY (EXHIBIT BSG/EMR-2) AND HIS RECOMMENDED IOWA 74-R3 LIFE AND CURVE FOR ACCOUNT 376.2 - COATED/WRAPPED STEEL MAINS? (POUS TESTIMONY, P. 35 LINE 22 – P. 36 LINE 13).

A. Again, Mr. Pous simply misinterprets the historical data and the likely impact of future activity on the average service life that can be achieved by this property category. Mr. Pous is quick to criticize the discussion of the range of the historical data provided within the depreciation study as opposed to thoroughly analyzing the study's analysis.

The crux of Mr. Pous' misinterpretation is his statement that no significant weight should have been given to the retirement data points beyond 53 years of age. Mr. Pous states that the retirements were too small to clearly represent the anticipated future service life parameter for this property category. The fallacy of

Mr. Pous' assumption is that he failed to consider the fact that the oldest existing vintage investment in this property category is 1953 (which is fifty years of age as of the study date). The dollar level of retirements over the past one to two decades averaged between $80,000 and $100,000 per year. Based upon this actual experience, it can be anticipated that annual retirements of this level (at a minimum) will occur in future years. Next, since the oldest vintage of surviving coated/wrapped steel mains is 1953 (50 years of age), future retirements cannot currently occur at ages greater than fifty (50) years of age. The occurrence of these retirements (at ages 50 years or younger) will automatically serve to either drive down the achieved average service life and/or if all the retirements occur at the maximum possible age (which is unlikely given past experience) the resulting average service life for the account cannot be greater than fifty (50) years. Mr. Pous' failure to recognize this factor demonstrates his lack of detailed analysis of the data.

The depreciation parameters for Account 376.2 - Coated/Wrapped Steel Mains, set forth in the depreciation report (Exhibit BSG-EMR-2), are clearly supported by the historical data and are appropriate for this property group.

Q. HOW DOES THE SERVICE LIFE PARAMETERS (IOWA 55-R2) COMPARE TO SIMILAR PROPERTY WITH OTHER OPERATING COMPANIES AS WELL AS WITH THE INDUSTRY IN GENERAL?

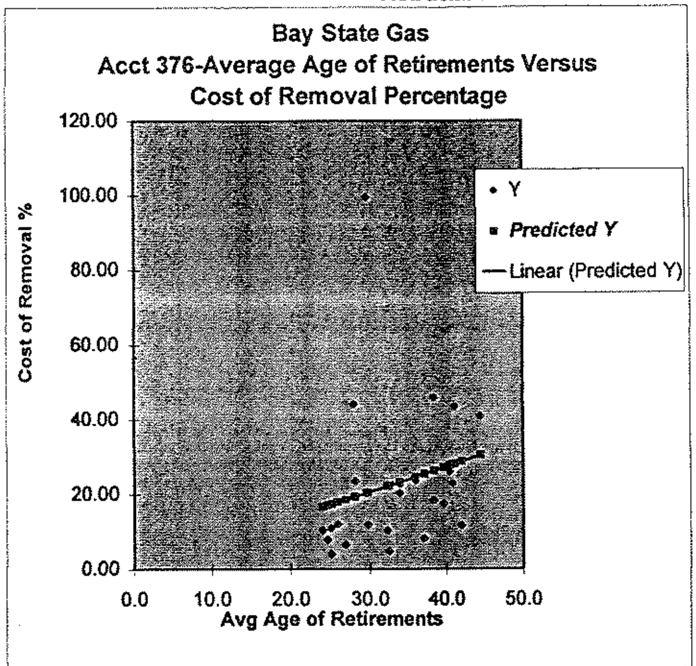
A. In reviewing Rebuttal Exhibit EMR-R3, it should be noted that of companies, for which the data was segmented by material type, only two of those companies studied experienced an average service life greater than fifty-five (55) years (the average service life recommended for Bay State's Account 376.2 - Coated/Wrapped Steel Mains). Numerous other companies experienced service lives shorter than the average service life recommended for Bay State's property group. For the companies with longer average service lives, the corresponding negative net salvage percentages for those companies are also higher (a higher negative net salvage results in a higher depreciation rate). In addition, the companies with higher average service lives for their overall Account 376 - Mains likely include a component of bare steel and cast iron mains (both categories of which routinely have experienced far longer service lives) which suggests that these other property categories (bare steel and cast iron) are contributing to the longer average service life for the total overall account analysis as opposed to the proposed service life for the Coated/Wrapped Steel property group.

With regard to the general industry, the mean average service life for Account 376 - Mains, of companies reporting to the AGA/EEI depreciation survey, is 55 years. (Rebuttal Exhibit EMR-R3).

Q. **DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes it does.

Rebuttal Exhibit EMR-R1



Bay State Gas

Account 376-Mains

Avg Age of Retirements Plot X-Axis	Cost of Removal Percent Plot Y-Axis
24.1	10.45
24.7	7.93
25.1	10.96
25.2	3.99
25.9	12.05
26.9	6.58
28.0	44.13
28.1	23.58
29.6	99.55
29.7	11.88
32.2	10.44
32.4	4.83
33.8	22.70
33.8	20.42
35.9	23.63
37.0	8.27
38.3	45.96
38.3	18.45
39.6	17.51
40.4	26.18
40.8	22.97
41.1	43.49
42.0	11.72
44.5	40.94

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.210062336
R Square	0.044128165
Adjusted R Square	0.000677375
Standard Error	20.71782508
Observations	24

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	435.920025	435.920025	1.01559	0.324523551
Residual	22	9443.022071	429.228276		
Total	23	9878.942096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	0.354397795	22.72868078	0.01559254	0.9877	-46.78200093	47.4908	-46.782	47.4908
X Variable 1	0.677356976	0.672137862	1.00776495	0.324524	-0.716571627	2.071286	-0.716572	2.071286

RESIDUAL OUTPUT

Observation	*Predicted Y*	*Residuals*
1	16.67870092	-6.228700924
2	17.08511511	-9.15511511
3	17.3560579	-6.376057901
4	17.4237936	-13.4337936
5	17.89794346	-5.847943462
6	18.57530046	-11.99530046
7	19.32039313	24.80960687
8	19.38812883	4.19187117
9	20.40416429	79.14583571
10	20.47189999	-8.591899992
11	22.16529243	-11.72529243
12	22.30076383	-17.47076383
13	23.24906359	-0.549063595
14	23.24906359	-2.829063595
15	24.67151325	-1.041513245
16	25.41660592	-17.14660592
17	26.29716999	19.66283001
18	26.29716999	-7.847169988
19	27.17773406	-9.667734057
20	27.71961964	-1.539619639
21	27.99056243	-5.020562429
22	28.19376952	15.29623048
23	28.8033908	-17.0833908
24	30.49678324	10.44321676

Rebuttal Exhibit EMR-R2

Uniform System Of Accounts For Gas Companies

Prescribed By

DEPARTMENT OF PUBLIC UTILITIES

OF

MASSACHUSETTS

REVISED EDITION

EFFECTIVE JANUARY [illegible]

:ount of long-term debt (including
ıred and unpaid, without specific
of payment and bonds called for

.ount of matured interest on long-
: utility at the date of the balance
to the principal of the debt on

mount of taxes collected by the
or otherwise pending transmittal
uthority.

:es assessed directly against the utility
y's own tax expense.

ccrued Liabilities.

ımount of all other current and
lsewhere appropriately designated
:ure of each liability.

:D CREDITS

bt.

ɔtal of the credit balances in the
ounts, for all classes of long-term
. (See account 181, Unamortized

ruction.

:es by customers for construction
ɔlly or in part. When a customer
ich he is entitled according to the
ıdvance was made, the balance, if
ɔe credited to account 271, Contri-

:e billings and receipts and other
for elsewhere, including amounts

which cannot be entirely cleared or disposed of until additional information has been received.

11. RESERVES

254. Reserve for Depreciation of Utility Plant in Service.

A. This account shall be credited with the following:

(1) Amounts charged to account 403, Depreciation Expense, to account 415, Income from Merchandising, Jobbing, and Contract Work, or to clearing accounts for current depreciation expense.

(2) Amounts charged to account 435, Miscellaneous Debits to Surplus, for past accrued depreciation.

(3) Amounts of depreciation applicable to utility properties acquired as operating units or systems.

(4) Amounts charged to account 182, Extraordinary Property Losses, when authorized by the Department.

(5) Amounts of depreciation applicable to utility plant donated to the utility.

B. At the time of retirement of depreciable utility plant in service, this account shall be charged with the book cost of the property retired and the cost of removal, and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirements, cost of removal and salvage are entered originally in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder. Upon completion of the work order, the proper distribution to subdivisions of this account shall be made as provided in the following paragraph.

C. For general ledger and balance sheet purposes, this account shall be regarded and treated as a single composite provision for depreciation. For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the utility department to which applicable. These subsidiary records shall reflect the current credits and debits to this account in sufficient detail to show separately (a) the amount of accrual for depreciation, (b) the book cost of property retired, (c) cost of removal, (d) salvage, and (e) other items, including recoveries from insurance.

Bay State Gas Company

Rebuttal Exhibit EMR-R3

Steel & Plastic Gas Distribution Mains and Steel & Plastic Services
(Summary of Depreciation Study Results of Various Depreciation Studies Perform By AUS Consultants Plus Additional Available New England Study Results)

Client	Study As Of Date	Steel-Coated & Wrapped Mains ASL/Curve	Steel-Coated & Wrapped Mains Net Salv %	Plastic Mains ASL/Curve	Plastic Mains Net Salv %	Steel-Coated & Wrapped Services ASL/Curve	Steel-Coated & Wrapped Services Net Salv %	Plastic Services ASL/Curve	Plastic Services Net Salv %
Commonwealth Gas	12/31/2001	65 (1)	-30% (1)			46 (2)	-75% (2)		
Connecticut Natural Gas	12/31/1997	62-R3 (1)	-75% (1)			50-R2 (2)	-175% (2)		
Great Plains Natural Gas	12/31/2001	60-R3	-55%	55-R3	-55%	45-R2.5	-120%	45-R2.5	-120%
Kansas Gas Service	12/31/2000	50-R2.5	-25%	50-R2.5	-25%	30-R1.5	-40%	30-R1.5	-40%
LG & E - Gas	12/31/2002	55-R3 (1)	-35% (1)			35-R2.5 (2)	-55% (2)		
Montana Dakota Utilites-Gas	12/31/2001	45-R3	-60%	45-R3	-60%	40-R2.5	-175%	40-R3	-175%
Northern Utilites-Maine	12/31/1990	50-R2	-20%	55-R3	-20%	40-S0.5 (2)	-150% (2)		
Northern Utilities-NH	12/31/2000	45-R3	-25%	50-R2.5	-25%	38-R1.5	-60%	40-R2.5	-60%
Oklahoma Gas Company	12/31/1997	44-R4 (1)	-15% (1)			30-R2.5 (2)	-35% (2)		
Providence Gas Co	9/30/1994	55-S3	-30%	45-R3	-50%	40-R4 (2)	-170% (2)		
Roanoke Gas Company	12/31/2002	43-S6 (1)	-30% (1)			35-S6 (2)	-65% (2)		
Rochester Gas & Electric	2003	80-h2.5 (1)	-65% (1)			44-h2.0 (2)	-15% (2)		
Southern Connecticut Gas	9/30/1998	70-R2.5	-20%	50-R2.5	-20%	45-R2	-125%	37-R2.5	-125%
Southwest Gas Corp-North	12/31/2002	35-R3 (1)	-15% (1)			30-R3 (2)	-35% (2)		
Southwest Gas Corp-South	12/31/2002	40-R2.5 (1)	-15% (1)			39-R3 (2)	-30% (2)		
Boston Gas	12/31/1992	62-R4 (3)	-60%	50-L3	-60%	40-L3 (2)	-150% (2)		

(1) Total Mains Account
(2) Total Services Account
(3) Includes Steel and Cast Iron

1998-AGA Survey-Mean Average		55	-36%			40	-53%		
Companies Reporting		98	66			71	37		
New England Company									
Current Bay State Gas	12/31/1998	85-R3	-10%	60-R3	-140%	55-R3	-140%	55-R3	-140%
Proposed Bay State Gas	12/31/2003	55-R4	-15%	55-S2	-15%	56-R3	-170%	55-R3	-170%

Bay State Gas Company
Total Company
376.40 (367.40) PLASTIC MAINS

Summary of Curve Fitting Results

User Selected

T-Cut Age None

Observed Life Table

Retirement Expr. 1975 - 2003
Placement Years 1971 - 2003

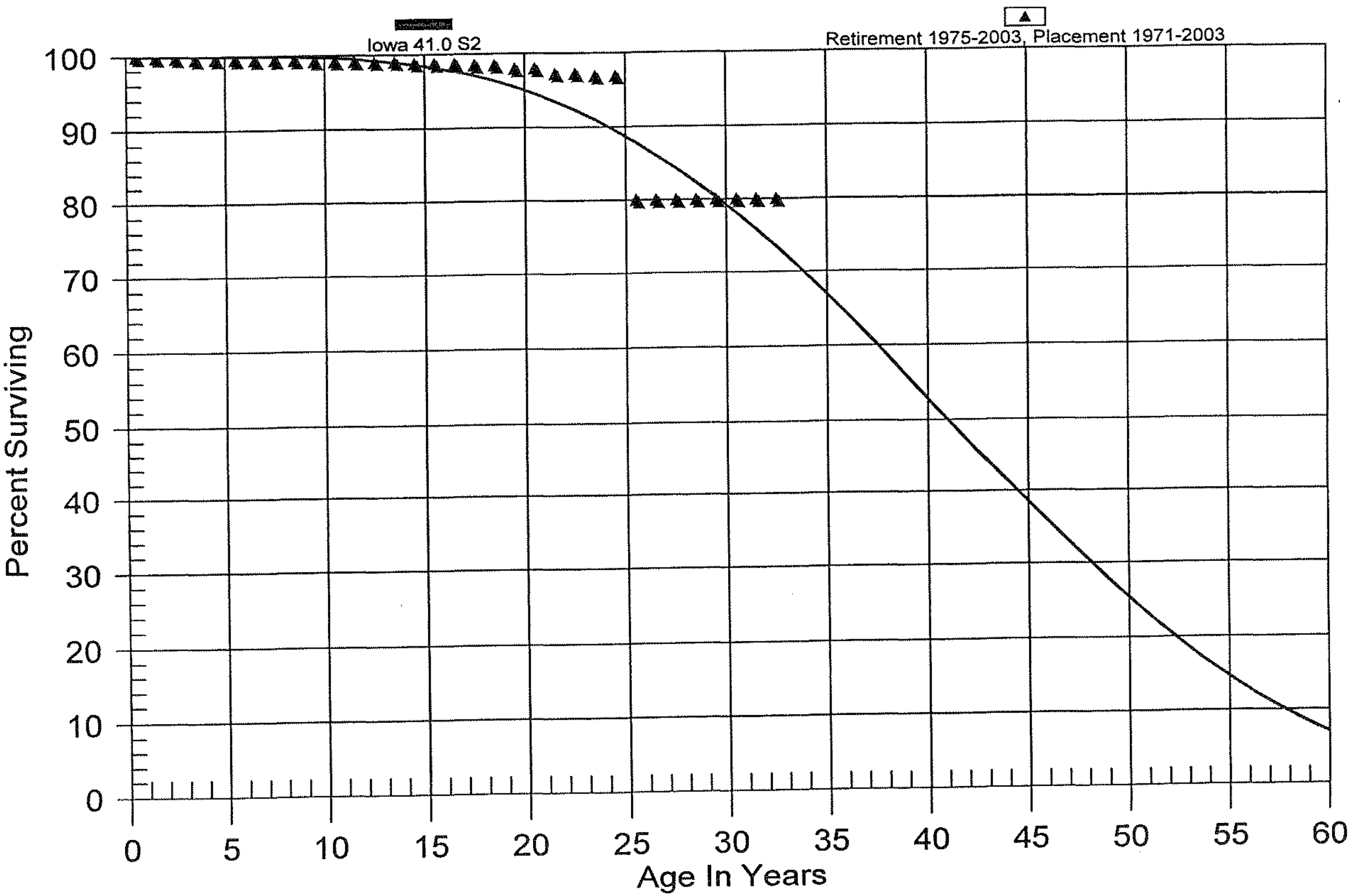
Max Exposure Age	32.5
Life Table % Surviving	80.0
Sum Of Life Table	29.9

Curve Fitting Period

	Full		15 - 85% Of ASL	
Rank	Life/ Curve	Least Sum Of Square	Life/ Curve	Least Sum Of Square
1	41-S2	301.39	29-S5	100.79
2	41-L3	304.67	30-R5	114.43
3	37-S3	309.40	28-S6	122.68
4	35-R4	314.00	31-L5	127.25
5	48-L2	345.82	32-S4	128.68
6	39-R3	362.85	34-L4	177.50
7	45-S1.5	364.02	36-S3	186.05
8	36-L4	383.58	34-R4	203.54
9	49-S1	426.66	40-L3	219.59
10	54-L1.5	462.49	42-S2	249.04
11	43-R2.5	485.52	50-L2	288.83
12	63-L1	532.57	48-S1.5	294.43
13	35-S4	550.67	41-R3	299.69
14	56-S0.5	552.24	55-S1	321.22
15	48-R2	608.29	62-L1.5	344.27
16	65-S0	648.69	49-R2.5	365.64
17	33-R5	679.55	74-L1	365.90
18	34-L5	681.97	67-S0.5	369.16
19	76-L0.5	692.12	83-S0	394.67
20	94-L0	778.89	61-R2	407.22
21	58-R1.5	779.37	101-L0.5	414.05
22	86-S.5	856.03	133-L0	428.51
23	73-R1	879.20	86-R1.5	448.10
24	95-R0.5	947.97	131-S.5	454.76
25	135-O2	978.45	116-R1	462.89
26	121-O1	978.87	160-R0.5	473.37
27	121-SC	978.87	175-O1	490.24
28	175-O3	1019.30	175-SC	490.24
29	33-S5	1048.20	175-O2	518.69
30	175-O4	1594.80	175-O3	821.60
31	33-S6	1671.40	27-SQ	857.64
32	32-SQ	2856.30	175-O4	1578.80

Bay State Gas Company

Total Company
376.40 (367.40) PLASTIC MAINS
Original And Smooth Survivor Curves



Bay State Gas Company
Total Company
376.40 (367.40) PLASTIC MAINS

Summary of Curve Fitting Results

User Selected

T-Cut Age 25 Years

Observed Life Table

Retirement Expr.	**1975 - 2003**
Placement Years	**1971 - 2003**
Max Exposure Age	25
Life Table % Surviving	96.8
Sum Of Life Table	24.2

Curve Fitting Period

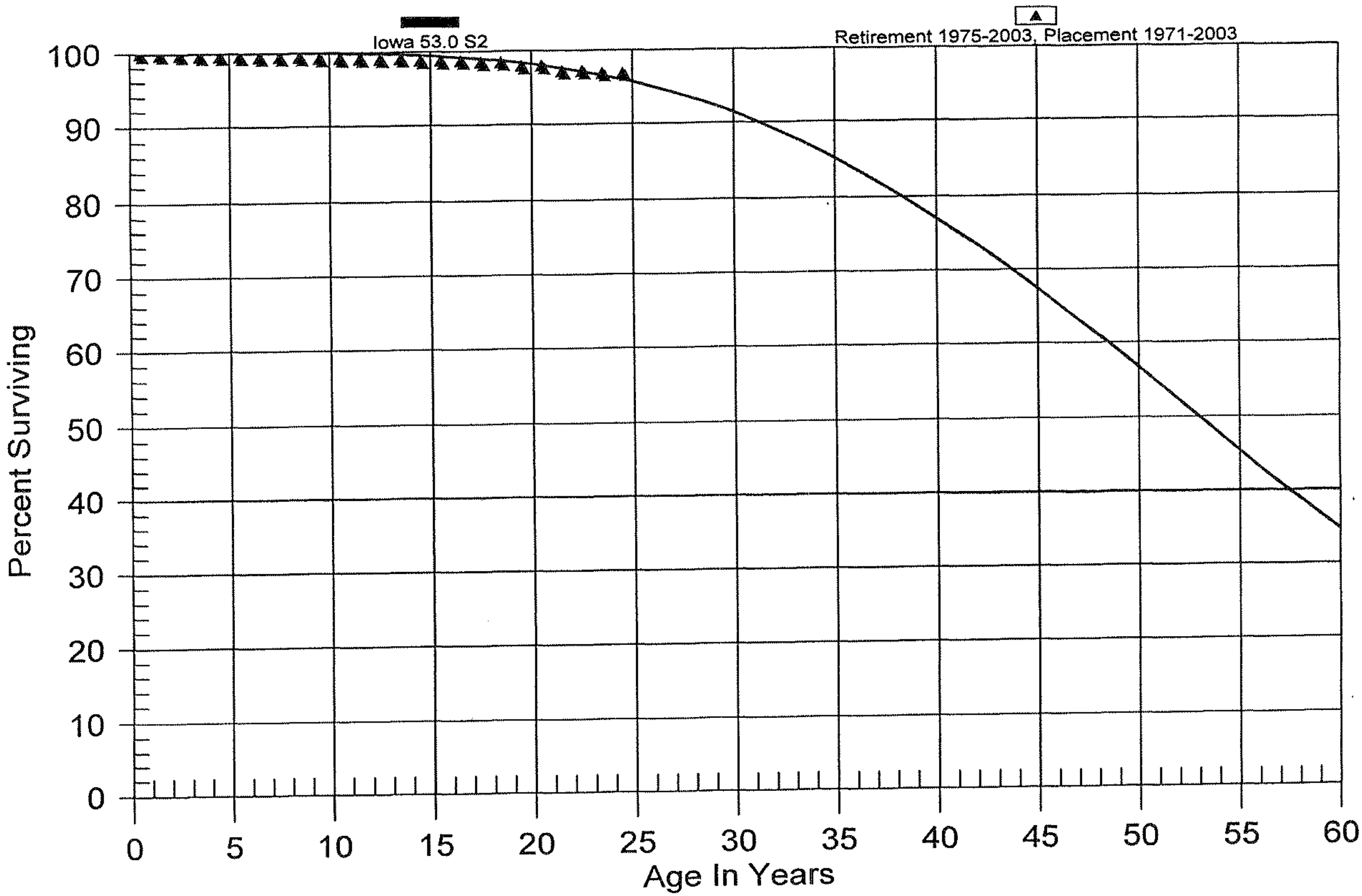
	Full		15 - 85% Of ASL	
Rank	Life/ Curve	Least Sum Of Square	Life/ Curve	Least Sum Of Square
1	120-L1	0.69	29-S5	100.79
2	94-L1.5	0.72	30-R5	114.43
3	59-R3	0.88	28-S6	122.68
4	106-S0.5	0.89	31-L5	127.25
5	139-S0	0.93	32-S4	128.68
6	84-R2.5	0.97	34-L4	177.50
7	175-L0.5	1.52	36-S3	186.05
8	117-R2	1.61	34-R4	203.54
9	77-S1	2.16	40-L3	219.59
10	70-L2	2.32	42-S2	249.04
11	175-R1.5	2.55	50-L2	288.83
12	65-S1.5	2.71	48-S1.5	294.43
13	50-L3	6.11	41-R3	299.69
14	53-S2	6.20	55-S1	321.22
15	42-R4	6.66	62-L1.5	344.27
16	42-S3	12.28	49-R2.5	365.64
17	39-L4	14.62	74-L1	365.90
18	175-R1	17.44	67-S0.5	369.16
19	33-R5	22.21	83-S0	394.67
20	35-S4	22.73	61-R2	407.22
21	175-L0	22.82	101-L0.5	414.05
22	33-L5	25.35	133-L0	428.51
23	175-S.5	30.11	86-R1.5	448.10
24	31-S5	33.23	131-S.5	454.76
25	28-S6	41.44	116-R1	462.89
26	25-SQ	58.78	160-R0.5	473.37
27	175-R0.5	75.05	175-O1	490.24
28	175-O1	175.42	175-SC	490.24
29	175-SC	175.42	175-O2	518.69
30	175-O2	248.53	175-O3	821.60
31	175-O3	702.34	27-SQ	857.64
32	175-O4	1564.60	175-O4	1578.80

Bay State Gas Company

Total Company

376.40 (367.40) PLASTIC MAINS

Original And Smooth Survivor Curves



5

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S PREFILED REBUTTAL TO THE FILED DIRECT TESTIMONY OF ALVARO PEREIRA

Witness:

Lawrence R. Kaufmann, Consultant (PBR)

IN SUPPORT OF
BAY STATE GAS COMPANY'S
REQUEST FOR INCREASE IN BASE REVENUE AND
OTHER RATE MODIFICATIONS

EXH. BSG/REBUTTAL-5

JULY 29, 2005

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I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lawrence R. Kaufmann. My business address is 22 East Mifflin, Suite 302, Madison, WI, 53703.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING ON BAY STATE'S PROPOSED PERFORMANCE-BASED REGULATION PLAN?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. This testimony will respond to the direct testimony of Dr. Alvaro Pereira of the Massachusetts Division of Energy Resources ("DOER"), including Dr. Pereira's recommendations for a performance-based regulation ("PBR") plan for Bay State.

Q. PLEASE SUMMARIZE DR. PEREIRA'S TESTIMONY.

A. Dr. Pereira supports the use of PBR for Bay State but has concerns about several aspects of the Company's proposed plan. His largest concern, apparently, is that he believes the Company has proposed a "partial PBR" since its proposal also includes a Steel Infrastructure Replacement ("SIR") program. Dr. Pereira recommends that the SIR be rejected, but he also recommends that the PBR plan be changed so that it in fact becomes a "partial PBR." Dr. Pereira also recommends a change in the Company's proposed earnings-sharing mechanism ("ESM"), "to better reflect the relatively riskless nature of gas distribution and bandwidths that have been approved elsewhere" (Pereira Direct Testimony, p. 3 lines 13-15). Dr. Pereira also recommends that the Department reject the Company's proposed tariff changes for dual-fuel firm customers (M.D.T.E. No. 67).

Q. WHAT IS YOUR GENERAL ASSESSMENT OF DR. PEREIRA'S TESTIMONY?

A. Dr. Pereira has put forward a thoughtful piece of testimony. I concur with his general support of PBR, and his recommendation to amend the Company's ESM may have merit. However, his evaluation of Bay State's PBR proposal is erroneous in several important respects, and his recommended changes to the plan will generally not support the Department's objectives for effective incentive regulation.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, I will address the PBR mechanism's application. Then the Company's proposed SIR mechanism, in general terms. Next, I will consider Dr. Pereira's recommended changes to the ESM. Then I will discuss the term of the PBR plan and how it relates to other adjustments of the Company's proposal. The testimony will end with a brief conclusion.

II. <u>THE APPLICATION OF PBR</u>

Q. WHY DOES DR. PEREIRA STATE THAT THE COMPANY HAS PROPOSED A "PARTIAL PBR"?

A. Dr. Pereira says "the Company is proposing a partial PBR that caps only a portion of their [SIC] costs, thus limiting the level of incentive for the Company to control its costs and improve productivity, thereby lowering the potential savings that would be normally possible under incentive regulation." (Pereira Direct Testimony, p. 3 line 28 – p. 4 line 2). Consistent with this view, Dr. Pereira says that only O&M costs, or approximately 50% of the Company's total costs, "would be theoretically influenced by the incentives of the PBR plan" (Pereira Direct Testimony, p. 5 lines 2-3). Because he views all remaining costs as essentially "sunk," and independent of the incentives created by PBR, he states: "if the Company's proposal is approved, ratepayers would be paying for a comprehensive PBR but only receiving the benefits of a partial PBR." (Pereira Direct Testimony, p. 5 lines 3-4).

Q. IS THIS AN ACCURATE CHARACTERIZATION OF THE COMPANY'S PBR PROPOSAL?

A. No. The Company has not proposed a partial PBR plan. Dr. Pereira's opinion that the plan is "partial" appears to rest on two mistaken foundations. First, Dr. Pereira implies that costs can be cleanly divided into two categories - "O&M costs" and "sunk costs" – and that only the former is subject to the incentives of the Company's proposed PBR mechanism. Second, Dr. Pereira seems to believe that even if productivity gains result entirely from O&M cost reductions, these productivity gains are independent of existing "sunk" costs, and therefore the PBR plan should exclude sunk costs. Neither premise is correct.

Moreover, if Dr. Pereira is correct that ratepayers are "paying for a comprehensive PBR but only receiving the benefits of a partial PBR," this conclusion would logically extend to any utility with "sunk" costs that cannot be reduced under a PBR plan. This would include every utility in Massachusetts for which a comprehensive PBR has been approved. Indeed, it would extend to energy utilities everywhere since a large portion of the prices paid for utility services invariably recover the costs of infrastructure that is already in service and cannot plausibly be reduced. If Dr. Pereira's position is taken to its logical end, then PBR plans *must* be "partial" for customers not to pay for more than they receive. But this conclusion contradicts Dr. Pereira's view that a partial PBR "represents a step backwards in terms of the evolution of incentive regulation as applied by the Department over the past decade." (Pereira Direct Testimony, p. 3, lines 27-28). I believe this contradiction also reflects the two fundamental mistakes discussed above.

Q. UNDER THE PBR PLAN, CAN ALL OF BAY STATE'S COSTS BE CLASSIFIED AS EITHER "O&M COSTS" OR "SUNK COSTS"?

A. No. During the term of the PBR plan, Bay State will continue to incur *new* capital costs that are subject to the PBR mechanism. Examples of these costs include services, meters and distribution mains that are installed to serve new customers on the system. The Company is also likely to undertake a variety of "discretionary" capital investments, like new and/or upgraded computer hardware and software. Such information technology assets depreciate rapidly and therefore typically have short replacement cycles. In addition, gas distribution infrastructure may be replaced during the term of the PBR plan that is not subject to the SIR. For example, the Company may replace regulators, cast iron mains, or polyethylene mains. All of these capital investments are subject to the PBR mechanism and not the SIR. Dr. Pereira is therefore incorrect in categorically stating that capital costs going forward will not be subject to the PBR mechanism. (Pereira Direct Testimony, p. 5 lines 23-25).

Q. UNDER THE PROPOSED PBR MECHANISM, ARE PRODUCTIVITY GAINS THE COMPANY MAY ACHIEVE NECESSARILY INDEPENDENT OF ITS "SUNK" COSTS?

A. No. It is true that a utility can influence the total factor productivity (TFP) gains it achieves only via "control" variables over which it exercises discretion. For energy utilities, the level of O&M costs is likely the main variable that can be managed to increase TFP growth over the term of a PBR plan. Dr. Pereira appears to reason that if TFP gains are mainly associated with changes in one particular set of costs, then PBR must only apply to this set of costs. One reason this conclusion is incorrect is that TFP gains will reflect the relationship between *incremental* cost changes (*e.g.* O&M cost reductions) and the existing level of costs. For energy utilities, most existing costs will be largely "sunk" since they pertain to the costs of infrastructure that is already in place. Accordingly, it is fallacious to conclude that TFP gains are independent of sunk costs and that sunk costs should be excluded from a PBR plan.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THIS POINT.

A. Please consider how economies of scale are realized. It is widely acknowledged that scale economies can be an important source of TFP gains for energy utilities. Economies of scale will be realized whenever the unit cost of service declines as output expands. This, in turn, will occur when the incremental cost (*i.e.* marginal cost) of providing the increased output is less than the existing average cost. As long as this is true, unit cost must decline and scale economies must be realized when output expands.

This is illustrated in economics textbooks with the classic graph of an average cost curve plotted against output. Output levels associated with increasing returns to scale are those where the average cost curve is declining, which in turn is true whenever the marginal cost curve is below the average cost curve.

Average cost for energy utilities necessarily includes the sunk costs of existing infrastructure. Hence, the realization of scale economies and its concomitant impact on TFP growth necessarily involves a relationship between incremental costs and existing sunk costs. TFP growth is therefore not independent of the existing cost base, including existing "sunk" costs, even if productivity gains result entirely from O&M cost reductions.

Q. PLEASE SUMMARIZE WHETHER THE COMPANY AND THE DOER HAVE PROPOSED A "PARTIAL PBR" THAT APPLIES ONLY TO O&M COSTS.

A. It is not accurate to say the Company has proposed a partial PBR that applies only to O&M costs. The Company's PBR proposal is much broader-based and covers all capital investments Bay State will be making during the term of the plan except the incremental investments for the SIR program.

Dr. Pereira, on the other hand, has proposed a partial PBR plan that applies only to O&M costs. This recommendation is puzzling since it runs counter to Dr. Pereira's opinion that a partial PBR would be a step backwards in the evolution of incentive regulation in Massachusetts and would not promote the Department's objectives of incentive regulation. The Department expressed a consistent view regarding the merits of broad-based and targeted incentive approaches in D.P.U. 94-158.

Q. WHAT IS YOUR CONCLUSION REGARDING THE DOER'S PROPOSED PARTIAL PBR MECHANISM?

A. Dr. Pereira's presented arguments, which are ultimately contradictory, do not support the partial PBR mechanism. A partial incentive mechanism that applied only to O&M costs would be a step backwards in the evolution of incentive regulation in Massachusetts and would not advance the Department's objectives. Accordingly, the DOER's proposed partial PBR should be rejected.

III. THE SIR MECHANISM

Q. ALTHOUGH THE COMPANY HAS NOT PROPOSED A PARTIAL PBR, IT HAS PROPOSED THE SIR PROGRAM IN ADDITION TO THE PBR MECHANISM. PLEASE DESCRIBE THE RATIONALE FOR SUCH A MECHANISM.

A. The SIR program, including the cost recovery mechanism, is designed to help the Company recover the costs associated with achieving its public safety and system integrity obligations. As described in the testimony of Mr. Bryant, the SIR program is motivated by the severe and accelerating leak problem on Bay State's bare and unprotected steel infrastructure. The Company has concluded that it must replace this infrastructure to remedy public safety concerns. Mr. Bryant has indicated that the Company will replace its entire bare and unprotected steel infrastructure regardless of whether the SIR program is approved. He has also indicated that in the absence of the SIR program, the Company believes it will not have a reasonable opportunity to recover the incremental investment costs of this replacement program and earn its allowed rate of return. The SIR program is therefore motivated by the Company's analyses of actions it must take to achieve its paramount objective of maintaining public safety while simultaneously recovering the costs necessary to achieve this goal.

Q. GIVEN THIS CONTEXT, ARE THERE BENEFITS ASSOCIATED WITH THE SIR PROGRAM?

A. I believe there are. Recall that Mr. Bryant has stated that Bay State will replace its entire steel infrastructure regardless of whether the SIR program is approved. The steel replacement program will therefore go forward either with or without the SIR program recovery mechanism. Given these two options, I believe customers will benefit if the costs of the program are recovered through the SIR program. Compared with the alternative of no SIR program, the two main benefits of the SIR program are lower procurement costs and lower regulatory costs. Mr. Bryant discussed both of these benefits in his direct testimony. If the SIR program is not approved, the Company will almost certainly incur higher costs of procuring and installing new infrastructure because vendors will charge higher prices if capital replacement takes place under a series of shorter-term contracts than under an approved longer-term program. The Company is also likely to incur higher regulatory costs without the SIR program if capital replacement depresses Return on Equity ("ROE") and prompts new rate case filings for cost recovery.

Q. DR. PEREIRA SAYS THE SIR PROGRAM WILL "INCREASE THE LEVEL OF UNCERTAINTY IN FUTURE RATE CHANGES" (DIRECT TESTIMONY P. 5, LINE 28). DO YOU AGREE?

A. No. This conclusion does not adequately consider the uncertainty of rate changes under the two alternatives that are before the Department (*i.e.*, steel replacement cost recovery with the SIR program and steel replacement cost recovery without the SIR program). The exact patterns of cost and rate changes are not known under either approach, but the total amount of capital to be replaced will be the same. This implies that the total cost of the capital replacement program without the SIR program will be at least equal to that under the SIR program. Indeed, I would expect total costs to be higher if the SIR program is not approved because of the higher procurement and regulatory costs discussed above. But even if the SIR program does not cause costs to decline, it will cause rates to change by relatively smaller increments at more frequent intervals. If the SIR program is not approved, rates would change less frequently, but by relatively larger increments. I believe the uncertainty of rate changes would decrease under the SIR program because rates would change by smaller amounts and rate changes would be subject to more year-to-year Department monitoring and oversight. Certainly, without the SIR program customers would perceive rate changes to occur with greater magnitude and suddenness. Also, without the SIR program rates are more likely to "ratchet" upwards unexpectedly, rather than to adjust in more gradual increments. Approving the SIR program would therefore likely cause less rate shock and less uncertainty regarding future rate changes, not more.

IV. ADJUSTMENTS TO THE EARNINGS SHARING MECHANISM

Q. WHAT IS DR. PEREIRA'S RECOMMENDATION REGARDING THE EARNINGS SHARING MECHANISM?

A. Dr. Pereira "recommend[s] a much more progressive ESM that returns any initial productivity gains going forward back to customers. Only at high rates of return or ROE, outside of a reasonable bandwidth, such as 200 basis points, should the Company retain some percentage of earnings. A 75% to shareholders and 25% to ratepayers split should only be applied after any initial savings have been passed to the Company's customers. Conversely, earnings that fall below the target ROE are retained by the Company but ratepayers should not have to be charged for any deficiencies in earnings due to the relatively riskless nature of Bay State's rate proposal" (Pereira Direct Testimony, p. 9, lines 22-29).

Q. DOES DR. PEREIRA'S RECOMMENDATION THAT THERE BE NO "DOWNSIDE" EARNINGS SHARING DEPEND ON WHETHER THE SIR PROGRAM IS REJECTED, AS HE RECOMMENDS?

A. Yes. Dr. Pereira says he would consider having the ESM share downside as well as upside earnings if the SIR is not approved. In such an instance, "the Company may require protection against earnings below the agreed upon benchmark. Thus, a sharing of downside risk with ratepayers would be appropriate." (Pereira Direct Testimony, p. 10, lines 8-9).

Q. DO YOU AGREE THAT AN ADJUSTMENT IN THE COMPANY'S PROPOSED ESM IS DESIRABLE?

A. I believe an adjustment to the Company's proposed ESM may have merit, but the appropriateness of such an adjustment depends on the details of the alternative. As I discussed in my oral testimony, I did consider proposing an alternative ESM in my Direct Testimony. Bay State was generally receptive to such a proposal. In the end, however, we decided to stick with the Boston Gas ESM precedent. The reason is that the Order in D.T.E. 03-40 that approved this ESM was based on a comprehensive Department review that was still quite recent at the time Bay State was preparing its proposal. To the extent possible, the Company did not want to replicate that review and the associated regulatory costs.

Q. DO YOU BELIEVE DR. PEREIRA' PROPOSED ADJUSTMENTS TO BAY STATE'S ESM ARE APPROPRIATE?

A. No. If I understand Dr. Pereira's testimony correctly, he is recommending that customers receive 100% of all earnings between the allowed ROE and 200 basis points above the allowed ROE. This approach would create the wrong incentives and could actually discourage the Company from taking actions that improve efficiency. For example, suppose Bay State is considering an initiative that requires upfront costs in Year 1, but will reduce costs and raise ROE by 100 basis points in each subsequent year. Under Dr. Pereira's proposal, Bay State would not choose to pursue this project since doing so would actually reduce its earnings (*i.e.*, the Company would incur the costs in Year 1, but not retain any benefits in subsequent years). Dr. Pereira's ESM proposal would therefore cause the Company to forgo initiatives that would improve its efficiency and ultimately benefit customers. This obviously runs counter to the Department's objectives for incentive regulation.

Dr. Pereira's proposed ESM also appears to be unprecedented. His survey of ESMs from other jurisdictions (Exhibit DOER-AEP-1) does not provide any examples of ESMs that return 100% of earnings immediately above the allowed ROE to customers. I am also not aware of any ESM of this form that has been approved anywhere in the world. Certainly, it is much more common for ESMs to define "bandwidths" as the earnings range in which sharing with customers is *not* triggered (as opposed to Dr. Pereira's formulation where *all* earnings within the bandwidth are returned to customers). Dr. Pereira's conception of a bandwidth is also not consistent with how the Department has applied this concept to previous ESMs it has approved.

Q. IF THE ESM IS TO BE ADJUSTED, WHAT WOULD YOU RECOMMEND?

A. If the ESM is to be adjusted, I would recommend narrowing the deadband (or bandwidth, in Dr. Pereira's terminology) from 400 basis points to 200 basis points. Outside the deadbands, I would propose 50/50 sharing. Equal sharing between customers and shareholders is obviously attractive in terms of simplicity and equity.

The ESM should also remain symmetric, so that upside and downside earnings can be shared. A symmetric ESM is essential if the SIR program is not approved, since the Company has estimated that the costs of replacing its steel infrastructure facilities will depress its earnings below allowed levels. However, even if the SIR program is approved, a symmetric ESM remains appropriate in terms of equity and to mitigate risk.

To protect against "extreme" earnings outcomes, the Department could also consider adding earnings caps and floors to the ESM. An earnings cap would be a maximum ROE level; 100% of earnings beyond this level would be credited to customers. An earnings floor would be a minimum ROE level; 100% of earnings below this level would be recovered from customers. An earnings floor would be especially warranted as a protection to the Company if the SIR program is not approved. If the Department believes earnings caps and floors are warranted, I would recommend setting the earnings floor at an ROE of 6.5% and the earnings cap be set at an ROE of 16.5%. The earnings floor would accordingly be 500 basis points below, and the earnings cap 500 basis points above, the Company's allowed ROE.

V. PBR PLAN TERM

Q. WHAT IS PROPOSED TERM OF THE COMPANY'S PBR PLAN?

A. The proposed term of Bay State's PBR plan is five years.

Q. THE LAST TWO PBR PROCEEDINGS IN MASSACHUSETTS THAT WERE NOT SETTLED APPROVED TERMS OF 10 YEARS. IN YOUR OPINION, IS 10 YEARS AN ACCEPTABLE TERM FOR A PBR PLAN?

A. It can be. As indicated in my oral testimony and in written responses to data requests, I am not opposed in principle to 10 year PBR plan terms. Compared with a five year PBR plan, a 10 year PBR term generally creates stronger performance incentives, facilitates longer-term utility planning, and reduces regulatory costs. At the same time, it must be recognized that 10 year PBR plans are riskier. Choosing between five-year and ten-year

PBR plans therefore involves assessing the tradeoffs between enhancing incentives and reducing regulatory costs, on the one hand, and mitigating risk on the other.

Q. GIVEN THE OBJECTIVES OF BOTH ENHANCING INCENTIVES AND MITIGATING RISK, DO YOU BELIEVE A 10-YEAR PBR TERM WOULD BE APPROPRIATE FOR BAY STATE IF THE SIR PROGRAM IS REJECTED?

A. No. Mr. Bryant has indicated that, for public safety reasons, Bay State will replace all the bare and unprotected steel on its system regardless of whether the SIR program is approved. This comprehensive steel replacement program is unique among Massachusetts gas distributors that have proposed PBR and it affects the balance of risks and incentives facing the Company. Bay State's analyses show that if the SIR program is not approved, there is a very high risk the Company will not be able to earn its allowed rate of return. A 10-year PBR plan is riskier than a five-year plan, so the risks facing the Company will be exacerbated by a longer plan term.

If the Department rejects the SIR program, it can nevertheless ameliorate the Company's greater capital replacement risks by approving a five-year plan. Such a plan would allow a more timely review of Bay State's steel replacement program. This review could, in turn, lead to the setting of new cast-off rates, changing the parameters of the indexing formula, or reconsidering the decision on the SIR program itself. It is appropriate for the Department to consider the balance of risks and incentives facing a particular utility when considering the optimal design of a PBR plan, including the plan term. If the SIR program is rejected, I believe the greater capital replacement risks facing Bay State should not be exacerbated by a ten-year plan term. Rather, it would be more reasonable to offset these greater risks, to some extent, by implementing a shorter five-year plan term.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Although Dr. Pereira has presented a thoughtful piece of testimony, his specific proposals for altering Bay State's PBR will not advance the Department's objectives for effective incentive regulation. The recommendation for a "partial" PBR is not supported by the arguments Dr. Pereira presents, and his proposal also contradicts his stated views about the desirability of such mechanisms. There is merit in potentially amending the Company's proposed ESM, but Dr. Pereira's proposed changes may undermine Bay State's performance incentives and not promote long-run customer benefit. If the Department wishes to amend the ESM, I would recommend a more straightforward reduction of the deadbands to 200 basis points and 50/50 sharing of earnings outside those bands. The Department should also consider the desirability of earnings caps and floors to mitigate "extreme" earnings outcomes. Finally, if the Department rejects the Company's proposed SIR program, it should approve a PBR term of five-years rather than 10 years since the longer plan term would exacerbate the Company's risk.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Subject to reserving my right to provide additional necessary information following receipt and review of Bay State's discovery of Mr. Pous, Yes.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

BAY STATE GAS COMPANY'S PREFILED REBUTTAL
TO THE FILED DIRECT TESTIMONY OF
NANCY BROCKWAY

<u>Panel Witnesses</u>:

Stephen H. Bryant, President
Danny G. Cote, General Manager

IN SUPPORT OF
BAY STATE GAS COMPANY'S
REQUEST FOR INCREASE IN BASE REVENUE AND
OTHER RATE MODIFICATIONS

EXH. BSG/REBUTTAL - 6

JULY 29, 2005

Q. **PLEASE STATE YOUR NAMES AND TITLES AND IDENTIFY WHETHER YOU FILED TESTIMONY PREVIOUSLY IN THIS PROCEEDING.**

A. [By Mr. Bryant:] My name is Stephen H. Bryant, President, Bay State Gas Company ("Bay State" or the "Company"). I filed testimony that has been identified in the record as Exh. BSG/SHB-1, as well as accompanying schedules and exhibits in support of Bay State's rate request.

A. [By Mr. Cote:] My name is Danny G. Cote, General Manager, Bay State Gas Company. I filed testimony that has been identified in the record as Exh. BSG/DGC-1, as well as related exhibits.

Q. **MR. BRYANT, IS BAY STATE'S SERVICE QUALITY MEETING THE STANDARDS DEMANDED BY THE DEPARTMENT?**

A. [By Mr. Bryant:] Yes, it is. In 2003 and in 2004, Bay State met all of its required metrics for service quality. Moreover, Bay State has been scrupulous in its measurement of these metrics and provided for the Department a detailed audit of its measurement statistics as part of this record. See Bay State's response to information request AG-18-8.

Q. MS. BROCKWAY REPEATEDLY CONFUSES BAY STATE'S PERFORMANCE ON SERVICE QUALITY METRICS WITH ITS AFFILIATE'S, NORTHERN UTILITIES. DOES THIS MAKE SENSE?

A. [By Mr. Bryant:] No. Ms. Brockway seems to believe that Bay State has "frequently" provided substandard customer service. This is simply not the case. Bay State has worked consistently over the last three years to improve its customer service in Massachusetts and all of its Bay State/Northern service territories, and has done so with improved technology and greater resource management.

Q. ARE THE METRICS AND MEASUREMENTS PROVIDED BY MS. BROCKWAY AT PP. 9-10 OF HER TESTIMONY THE APPROPRIATE METRICS FOR BAY STATE?

A. [By Mr. Bryant:] No. The first table on Page 9 refers to the monthly percentage of calls answered within 30 seconds. Although monthly figures provide an indication of performance at any given time, Bay State's approved service quality benchmark is an annual percentage, which the Company met in 2003. The second table refers to the average speed of answer. While Northern Utilities is measured on this standard, Bay State is not. In Docket No. 01-182, Northern

Utilities agreed to certain service quality standards for its New Hampshire Division. Although the Company was subject to certain penalties during 2003, average speed of answer is only a reporting requirement, and Northern Utilities has been fully compliant with all service quality standards since June 2003.

Q. ON MANY OCCASIONS THROUGHOUT HER TESTIMONY, MS. BROCKWAY STATES OR INFERS THAT BAY STATE RECEIVES SHORT-SHRIFT FROM NISOURCE, WHETHER IT BE THROUGH STAFFING OR OTHER INITIATIVES. IS THIS TRUE?

A. [By Mr. Bryant:] No. Local Bay State resource managers have been responsible for staffing in Massachusetts that affects service quality issues. Moreover, in early 2004, NiSource shifted to a much more local management structure, which permits a greater amount of local management and responsibility to be vested in the officers on the ground in any respective NiSource operating company's service area. As President of Bay State, I am part of that change in management structure, and am responsible for ensuring that Bay State meets all of its service quality standards while providing high quality and least cost service to its customers. The result is, and will continue to be, a higher sensitivity to the needs of its local communities and customers.

Q. ON PAGE 23 OF HER TESTIMONY, MS. BROCKWAY ACKNOWLEDGES BAY STATE'S NEED TO REPLACE BARE AND COATED UNPROTECTED FACILITIES "ON AN AGGRESSIVE SCHEDULE." PLEASE COMMENT.

A. [By Mr. Cote:] Yes. This statement seems to directly support Bay State's need for a Steel Infrastructure Replacement ("SIR") program.

Q. ON PAGE 23 OF HER TESTIMONY, MS. BROCKWAY PROVIDES CERTAIN RELIABILITY METRICS. PLEASE COMMENT.

A. [By Mr. Cote:] Ms. Brockway's use of reliability metrics is very narrow. Moreover, several other crucial safety metrics appear to be missing, in particular some that Bay State excels in that demonstrate service integrity, reliability and safety. For example, Bay State has not had a serious unplanned interruption due to operator error in four (4) years. Bay State's annual third party damage rates-per-thousand-locates has declined steadily over the last five (5) years and as of June 2005 stands at .2%. Third party damage is the leading cause of serious incidents, nationally. Further, Bay State's Type 2 leak backlog at year-end 2004 was completely eliminated. In addition, Bay State's leakage survey practice actually exceeds state and federal requirements, and has for years.

Q. **DO YOU AGREE WITH THE ANALYSIS OF THE RELIABILITY METRICS SELECTED BY MS. BROCKWAY?**

A. [By Mr. Cote:] No. I do not agree with her analysis. Ms. Brockway's analysis focuses only on dollars of capital and O&M expenditures. Her base assumption appears to be that a utility must continue to increase capital and O&M expenditures annually in order to be considered prudent. Ms. Brockway does not consider that increased productivity in O&M and the pattern in how capital dollars are spent (e.g., significant non-revenue producing investments in a given year can often be followed by apparent reductions in expenditures in following years) impact the annual year-to-year levels of expenditures. Reasonable utility management and practice require that Bay State continue to use resources more efficiently. In fact, the Department has instituted rate freezes or performance based ratemaking plans specifically to encourage utilities to become more efficient with their resources.

Q. HOW DOES BAY STATE RESPOND TO MS. BROCKWAY'S EVALUATION OF ITS HISTORICAL CAPITAL EXPENDITURES?

A: [By Mr. Cote:] On page 24, beginning at line 21, Ms. Brockway finds fault with Bay State's historical capital expenditures and claims that gas utilities should always "show a pattern of persistently increasing [capital] expenditures overtime." Ms. Brockway's claim is simplistic and would result in imprudent investments and higher rates for customers. Gas utility capital expenditures involve a complex process of addressing system requirements while balancing the limitations and complications associated with available workforce, coordination with state, municipal and private entities, weather, rate impact, need and numerous other significant drivers. Bay State has made prudent decisions each year to define the level of capital requirements and capital investments on our system. These prudent decisions have resulted in capital expenditures that vary from year-to-year since they do not follow the formulaic approach to continuously higher capital expenditures that Ms. Brockway advocates.

The notion that a company needs to "show a pattern" of continually increasing capital costs does not take into account the quality and useful life of individual systems. Further, to increase spending without an evaluation of specific system performance would invite replacement before it is necessary, thereby inefficiently using limited resources and capital that can be used to serve customers better elsewhere.

Q. CAN YOU OFFER BETTER AND MORE STANDARD INDUSTRY MEASURES OF SAFETY AND RELIABILITY THAN MS. BROCKWAY'S FOCUS ON CAPITAL AND O&M EXPENDITURES?

A. [By Mr. Cote:] Yes. Bay State believes that monitoring the system for gas leaks and repairing gas leaks on a timely basis should be the primary measures of a utility's safe and reliable operation, not dollars expended. The Department of Transportation, Office of Pipeline Safety ("OPS"), the federal agency responsible for monitoring and regulating the natural gas industry, has established and tracks 13 measures centered on reliability and safety. All of the OPS measures focus on the number of leaks and the ability of the utility to complete timely leak repairs. Every utility regulated by the

OPS must report their annual performance relative to these measures. The OPS measures include:

i. leaks- mains -total repaired/eliminated during year due to corrosion
ii. leaks- services -total repaired/eliminated during year due to corrosion
iii. leaks- mains -total repaired/eliminated during year caused by 3rd party
iv. leaks- services -total repaired/eliminated during year caused by 3rd party
v. leaks- mains -total repaired/eliminated during year caused by outside force
vi. leaks- services -total repaired/eliminated during year caused by outside force
vii. leaks- mains -total repaired/eliminated during year caused by construction defect
viii. leaks- services -total repaired/eliminated during year caused by construction defect
ix. leaks- mains -total repaired/eliminated during year caused by material defect
x. leaks- services -total repaired/eliminated during year caused by material defect
xi. leaks- mains -total repaired/eliminated during year caused by other
xii. leaks- services -total repaired/eliminated during year caused by other
xiii. leaks- total number of leaks remaining at the end of the year

In addition, the Department has stringent leak survey requirements for all gas utilities that it regulates.

Q. HOW DOES BAY STATE PERFORM IN THESE SAFETY AND RELIABILITY MEASURES RELATIVE TO ITS PEERS

FOR THE OPS MEASURES AND RELATIVE TO THE DEPARTMENT'S SURVEY REQUIREMENTS?

A. [By Mr. Cote:] According to RJ Rudden, who examined exactly this point, Bay State performs extremely well relative to its peers and the Department's requirements.

Q. ON PAGES 25 AND 26 OF HER TESTIMONY, MS. BROCKWAY INDICATES THAT FLAT SPENDING ON T&D EQUATES TO A DIMINUTION OF SYSTEM MAINTENANCE. HOW DO YOU RESPOND?

A. [By Mr. Cote:] There is no evidence to support the contention that flat spending on T&D equates to a degradation of prudent system maintenance. There has been a continuous effort at Bay State and other utilities under rate freezes to manage productivity and utilize resources more effectively. Bay State always endeavors to meet its obligations as a prudent operator and to ensure code compliance. For example, Bay State is substantially in compliance with the Department's 7-year meter change program, and is consistently a top performer in management of Type 2 leaks.

Q. ON PAGE 27 OF HER TESTIMONY, MS. BROCKWAY REFERS TO NEW JERSEY NATURAL AS A HIGH ACHIEVER IN EMERGENCY CALL RESPONSE TIME. PLEASE COMMENT.

A. [By Mr. Cote:] The obvious questions unanswered by Ms. Brockway's testimony are: What resources was this utility required to divert in order to achieve this level of response? What was the incremental cost vs. a 95, 96 or 97% level, recognizing that those last few percent can be very costly to produce and do they necessarily translate into safety?

Q. ON PAGE 28 OF HER TESTIMONY, MS. BROCKWAY INDICATES THAT BAY STATE RETURNED LOCATING TO AN IN-HOUSE FUNCTION FOLLOWING THE ATTLEBORO INCIDENT, WHICH HAS BEEN THE SUBJECT OF SOME DISCUSSION ON THIS RECORD. HOW DO YOU RESPOND?

A. [By Mr. Cote:] The subsequent remedial measures taken by Bay State following the tragic Attleboro incident have no relevance at all to this proceeding. It was a sound and reasonable management decision to review and to revise a course of action in the aftermath of such an incident, especially to examine the confluence of events that brought it about. However, the management decision to permit third-party outsourcing was not in and of itself the problem. In fact, Northern (Bay State's affiliate in Maine and New Hampshire) has continued since 1998 to successfully outsource locates with no incidents. Moreover, unfortunately, the same kind of locating errors are possible by both internal staff and third-party contractors.

Q. ON PAGES 30 AND 31 OF HER TESTIMONY, MS. BROCKWAY INDICATES THAT THE DEPARTMENT SHOULD IMPUTE REVENUES TO THE COMPANY THAT WOULD COMPENSATE RATEPAYERS FOR A PURPORTED LACK OF COMMITMENT TO SYSTEM EXPANSION. PLEASE COMMENT.

A. [By Mr. Bryant:] These statements are without foundation and reflect an unusual view of how the natural gas distribution business works relative the economy as a whole. Ms. Brockway did not take into account the difference in natural gas commodity prices between 1993 to 1998 versus 1998 to 2003, and her testimony does not reflect the impact of a recession that hit in 2002. The testimony also fails to mention the relative cost of natural gas versus oil during that same time period.

Q. **IN ANY EVENT, IS MS. BROCKWAY'S PROPOSAL, TO IMPUTE REVENUES, A FEASIBLE REGULATORY RESPONSE?**

A. [By Mr. Bryant:] No, it is not. Bay State's sales have increased, albeit at a rate slower than anyone expected in the energy euphoric late 1990's. Bay State was not alone in that optimism. Today, however, such amounts attributed to revenues somehow unachieved would be entirely speculative and such an adjustment would be unfounded and without basis on this record.

Q. **AS PART OF MS. BROCKWAY'S CRITIQUE OF THE NISOURCE PLANS TO OUTSOURCE CERTAIN BUSINESS FUNCTIONS, MS. BROCKWAY INFERS THAT NUMEROUS OF IBM'S PRIOR COMMITMENTS RELATED TO OUTSOURCING HAVE GONE SOUR. DOES THIS STATEMENT COMPORT WITH YOUR UNDERSTANDING?**

A. [By Mr. Bryant:] Actually, NiSource conducted extensive due diligence on IBM as part of its selection of IBM for this important business initiative. Following interviews and site visits, and a demanding review of IBM's ability to meet the individual and specified criteria for service quality that is required by its operating companies, NiSource determined that IBM was the best choice of potential allies. Moreover, NiSource verified that IBM was a valuable business partner engaged in continuing broad scale business service relationships with many large corporations, such as Procter & Gamble, Dun & Bradstreet, Marathon Oil Corp., the U.S. Postal Service, and Boeing. Of utilities in particular, a notable example for outsourcing is IBM's continuing successful partnership with Xcel Energy. Ms. Brockway briefly mentions this engagement on page 36, line 11 of her testimony, but does not indicate its success.

Q. **DO YOU HAVE LINGERING CONCERNS THAT IBM WILL NOT FUNCTION IN THE VARIOUS ROLES WITH WHICH IT WILL BE CHARGED UNDER THE AGREEMENT?**

A. [By Mr. Bryant:] No, I do not. Moreover, the Department has sufficient regulatory tools at its disposal to monitor and assure itself that Bay State will continue to adhere to its high levels of customer service quality and satisfaction.

Q. **WILL BAY STATE ENSURE THAT IT FOLLOWS ALL LAWS RELATED TO ITS COLLECTIVE BARGAINING**

AND THAT WILL IT CONDUCT NEGOTIATIONS WITH THE UNIONS IN GOOD FAITH?

A. [By Mr. Bryant:] Yes, it will.

Q. MS. BROCKWAY BELIEVES THE METSCAN PURCHASE WAS IMPRUDENT AND THAT THE TOTAL LEASE BUY-OUT PAYMENT FOR THE METSCAN METERS IS UNKNOWN. HOW DO YOU RESPOND?

A. [By Mr. Bryant:] Bay State's decision to install the devices was reasonable and prudent based on what the Company knew or should have known at the time. Further, the Metscan units provided customer benefits such as more accurate and timely meter readings and bills while improving operating efficiencies that lead to cost savings. The Company removed the amounts still in rate base at the end of the year and the lease payment from O&M expense, thus the pay off of the lease payment amount is known, and should be treated as a non-recurring cost and amortized over a reasonable period.

Q. MS. BROCKWAY HAS INDICATED THAT SHE HAS NEVER SEEN A COMPANY SO POORLY MANAGED. SHE RECOMMENDS THAT THE DEPARTMENT REDUCE THE

ALLOWED RETURN BECAUSE OF MANAGEMENT INEFFICIENCIES. HOW DO YOU RESPOND TO THIS?

A. [By Mr. Bryant:] This allegation is unfounded and simply does not comport with the facts. Bay State has met its service quality standards in 2003 and in 2004. It has operated successfully during a rate freeze since 1998. It has merged with highly competent natural gas companies, bringing to it the expertise and knowledge of the third largest natural gas distribution utility in the country. It benefits from this strength of size, while maintaining the attention of local management. Bay State is committed to being a community participant, and is a consistently strong performer in the natural gas industry.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. [By Messrs. Bryant and Cote:] Yes, subject to reserving my right to provide additional necessary information following receipt and review of Bay State's discovery.